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Evaluation of Long-Term NOx Reduction on Pulverized-Coal-Fired Steam Generators

KVB, Inc., Irvine, CA

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Industrial Environmental Research Lab.
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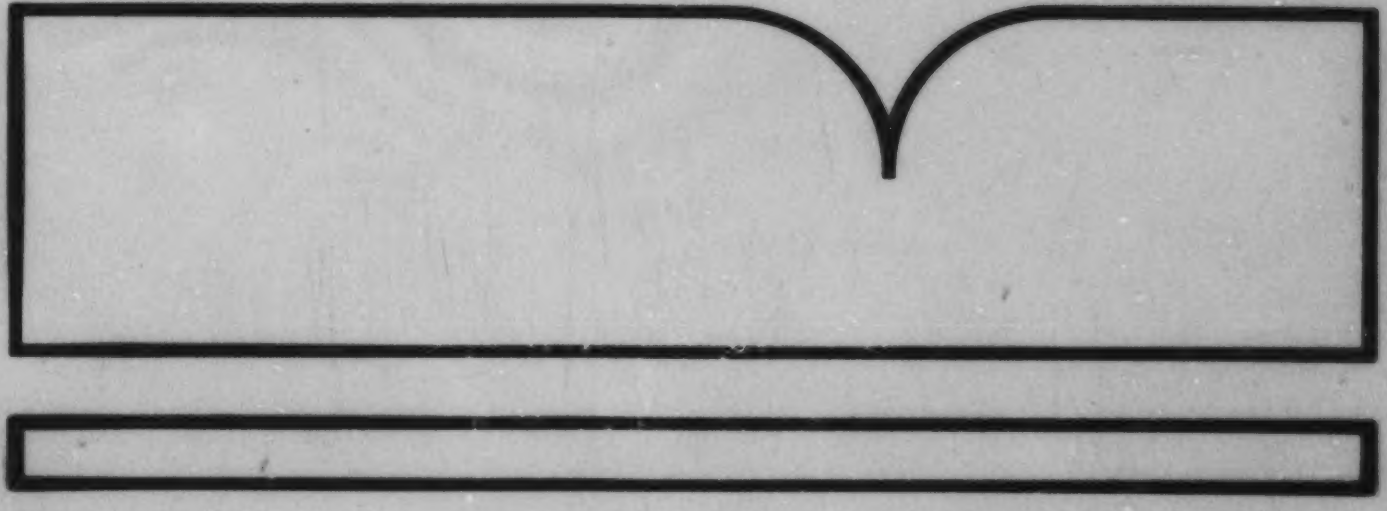

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EVALUATION OF LONG-TERM NO_x REDUCTION ON PULVERIZED-COAL-FIRED STEAM GENERATORS

by

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16. ABSTRACT The report gives results of analyzing long-term nitrogen oxide (NOx) emission data from eight pulverized-coal-fired steam generators, for the purpose of quantifying the effectiveness of various combustion modifications. All boilers, but one, were modified to reduce NOx emissions. The modifications included changing both hardware and operating procedures. All boilers were subject to the NOx provisions of the 1971 New Source Performance Standards (NSPS). In several instances, when long-term emission data for the period before the modification were not available, the quantification of the NOx reduction was based on the result of the performance test required by the 1971 NSPS. NOx reductions of from 5.1 to 60% were determined without incurring significant adverse impacts on unit operation. NOx emission levels, determined from the performance tests, were from 146 to 473 ng/J (0.34 to 1.10 lb/million Btu) before control implementation, and from 148 to 281 ng/J (0.34 to 0.65 lb/million Btu) after combustion modifications were applied.

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Nitrogen Oxides	Stationary Sources	07B
Boilers	Combustion Modification	13A
Coal		21D
Pulverized Fuels		
Combustion Control		21B

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ABSTRACT

Long-term NO_x emission data from eight pulverized-coal-fired steam generators were analyzed for the purpose of quantifying the effectiveness of various combustion modifications. All of these boilers, except one, were modified specifically to reduce NO_x emissions. These combustion modifications included changes of both a hardware and operational nature. All of the boilers were subject to the NO_x provisions of the 1971 New Source Performance Standard (NSPS).

In several instances long-term emission data for the time period before the modification were not available. In these cases the quantification of the NO_x reduction was based on the result of the performance test required by the 1971 NSPS. NO_x reductions ranging from 5.1 to 60 percent were determined without incurring significant adverse impacts on unit operation. NO_x emission levels, as determined from the performance tests, ranged from 146 to 473 ng/J (0.34 to 1.10 lb/10^6 Btu) before control implementation and from 148 to 281 ng/J (0.34 to 0.65 lb/10^6 Btu) after combustion modifications were applied.

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SECTION 1.0

BACKGROUND AND OBJECTIVES

During the course of Contract 68-02-3175, Work Assignment No. 8 (Reference 1-1), several pulverized-coal-fired steam generators which had been modified for the express purpose of reducing their NO* emission level were identified. These modifications included changes of both a hardware and operational nature, e.g., burner replacement, optimization of the overfire air system.

The primary objective of the present Work Assignment was to quantify the NO_x reduction on a long-term basis (approximately 30-days) by analyzing continuous emission monitor (CEM) data obtained before and after the modification. Whenever possible, the effect of the modification on unit heat rate (efficiency) was also to be quantified.

Also, the plant operating personnel were contacted in order to determine the effect of the modification on unit operation, e.g., any tendency observed for increased slagging/fouling/corrosion.

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*The EPA allows the use of NO-only analyzers to satisfy the requirement to measure "oxides of nitrogen." On a mass basis ($lb/10^6$ Btu or ng/J), all values of NO or NO_x reported herein are in terms of NO_2.

SECTION 2.0

APPROACH

2.1 DATA PACKAGES

Each of the participating organizations was requested to supply a data package consisting of:

1. Hourly averaged values of NO and O_2 (or CO_2) as measured by a certified continuous emission monitor (CEM).
2. Hourly averaged unit load in terms of either generator gross MWe or steam flow.
3. Hourly averaged unit heat rate (if available) in terms of Btu/kW•h (electric).
4. Results of periodic coal analyses.
5. CEM certification report.
6. Details of unit modification(s).
7. Results of unit performance test (as required by 1971 NSPS).

It was also requested that Items 1-4 should span, as a minimum, 30-days before and 30-days after the modification.

2.2 DATA ANALYSIS

The data packages received from the participating organizations were reviewed for completeness and legibility. Any discrepancies were resolved by telephone communications.

The hourly averaged values of NO, O_2 (or CO_2), heat rate and load were then analyzed by an expanded version of the data reduction computer program described in Reference 2-1. This program sorts the data in several modes to produce:

1. Mean and standard deviation of NO, O_2 (or CO_2), load and heat rate on a daily basis.

2. Mean and standard deviation of NO, O_2 (or CO_2), load and heat rate sorted by time of day (diurnal characteristic).

3. Mean and standard deviation of NO, O_2 (or CO_2) and heat rate sorted by load (into ten load increments).*

4. Load probability.

5. Separate linear regressions of NO vs. O_2 (or CO_2), one regression for each of the ten load increments.

6. NO probability.

7. Periods of excess NO_x emissions with respect to the 1971 NSPS on both a 3-hour rolling average and 3-hour block average basis.

8. Potential compliance with the NO_x provisions of the 1978 NSPS on a 30-day rolling average basis.

Optional input allows Items 3, 4 and 5 to be developed for a prescribed load range. This option facilitates the comparison of different data sets obtained on the same unit or nominally identical units.

In actual usage, the basic unit characteristics of NO and O_2 (or CO_2) vs. load (Item 3) were the most significant analysis result. These characteristics were used to quantify the effectiveness of the modification(s) in reducing NO, with the quantification based on a comparison of the data obtained before and after the modification(s). This approach would tend to minimize or eliminate the effect of, for example, seasonal load schedules on data interpretation.

In several instances long-term data were not available for the time period prior to the modification(s). In these instances the effect of the modification(s) on NO was assessed on the basis of the performance test (as required by the 1971 NSPS) and the long-term data obtained after the modification(s). Therefore, in these instances the quantification of the NO reduction could be made only at high load conditions.

---

*When appropriate, subsequent discussions will refer to differences in boiler characteristics within the ten load increments ("cells").

Periods of excess emission, if any, with respect to the 1971 New Source Performance Standard were expressed on a percentage basis. This approach was adopted because of the different amount (hours) of CEM data provided for each of the units analyzed. For example, 626 hours of data were provided for Unit A (Section 5) which would yield:

624 3-hour rolling averages (626 - 2)

208 3-hour block averages (626/3)

It was determined that Unit A had eight periods of excess emission on a rolling average basis and four periods of excess emission on a block average basis. Therefore, on a normalized basis (i.e., with respect to the total number of averages) these periods of excess emission would be 1.3 percent and 1.9 percent, respectively.

Potential compliance with the 1978 NSPS was usually established by comparing the NO probability distribution (Item 6, above) with the appropriate NO_x limitation (a function of coal type). This approach avoided the necessity of invoking on a priori assumption as to the NO probability distribution (e.g., normal distribution). This approach was required as, typically, the CEM data provided by the participating organizations was sufficient to calculate only a few 30-day rolling averages. This analysis would quantify the percentage of time for which the hourly averaged NO was less than or equal to the 1978 NSPS limitation.

It is not to be inferred that the percentage of time for which the hourly averaged NO exceeded the 1978 NSPS unequivically represents periods of noncompliance since these periods could be offset by lower emission values on a 30-day averaging basis.

Each participating organization was furnished with a draft report describing the results obtained for their unit(s). They were requested to review the report for accuracy and advise KVB of any discrepancies.

SECTION 3.0

DATA BASE AND SUMMARY

Data packages were received for eight steam generators operated by six organizations. Table 3-1 summarizes the pertinent characteristics of these units, the combustion modification(s) implemented as well as the long-term NO_x reduction achieved at high load.

Some explanation is in order with regard to two of the modifications shown in Table 3-1:

UFA - underfire air ports were added to the unit.
OFAA - the existing overfire air system was adjusted.

Further, the NO_x reduction was evaluated with the unit operating at or near full rated output. Differences, if any, in the NO_x reduction at other than rated output are discussed in the appropriate sections of this report.

In those cases where long-term data was not available before the modification the NO_x reduction was established by comparing the performance test NO_x ($NO + NO_2$) with the NO-only continuous emission analyzer. Comparisons of this type will introduce small errors in the NO_x reduction calculation. (Reference 3-1 reported that NO_2 was less than 5 percent of NO_x for pulverized-coal-fired utility boilers.)

The NO_x reductions shown in Table 3-1 ranged from 5.1 percent (for lower excess air) to 60 percent (for a combination of lower excess air and an adjustment of the overfire air system). For Nebraska Public Power District, Gentleman Station Unit 1, two values of the NO_x reduction are noted. This is due to a difference in interpretation by the utility of the performance test NO_x measured before the modifications.

Also shown in Table 3-1 are the post modification NO levels which correspond to the CEM data obtained during high load unit operation.

TABLE 3-1. DATA BASE AND HIGH LOAD NO_x REDUCTION

Utility	Station	Unit	Boiler Mfg.[1]	Coal Type[2]	Gross MWe	Modification[3]	NO_x Reduction, %	Post Mod. NO ng/J
Iowa Power & Light	Council Bluffs	3	B&W	Sub	720	LEA	5.1	148
Utah Power & Light	Hunter	2	CE	Bit	425	LNCFS,OFAA	39	155
Proprietary	-	A	RS	Bit	417	RB,UFA	40	269
Proprietary	-	B	RS	Bit	360	RB	40	279
	-	C	RS	Bit	360	RB	41	245
Nebraska Public Power District	Gentleman	1	FW	Sub	680	OFAA,LEA	49,60	188
Proprietary	-	D	B&W	Bit	81.9[4]	CO	15	281
		E	B&W	Bit	81.9[4]	CO	21	236

(1) B&W = Babcock & Wilcox
CE = Combustion Engineering
RS = Riley Stoker
FW = Foster Wheeler

(2) Sub = Subbituminous
Bit = Bituminous

(3) LEA = Lower excess air
LNCFS = Low-NO_x concentric firing system
OFAA = Overfire air adjustment
RB = Reburnering
UFA = Underfire air added
CO = CO-based control

(4) Rated steam flow, kg/s

SECTION 4.0

IOWA POWER & LIGHT, COUNCIL BLUFFS STATION, UNIT 3

4.1 INTRODUCTION

This boiler was manufactured by Babcock & Wilcox and is equipped with 56 dual register burners and a compartmented windbox. There are four rows of eight burners each on the front face and three rows of eight burners each on the rear face. The generator is rated at 720 gross MWe.

Data packages were obtained for the time periods of:

16 February 1981 - 29 May 1981

30 May 1982 - 15 July 1982

These packages consisted of hourly averaged NO and CO_2 as measured by the in-situ continuous emission monitor (CEM), hourly averaged gross MWe, hourly averaged net heat rate (Btu/net kW•h), periodic coal analyses, and the CEM certification report.

During the 1982 time period the unit was operated at a higher stack oxygen level in an attempt to reduce slagging tendencies. However, this approach was not subsequently adopted on a full-time basis. In this respect, the unit does not conform exactly to the objective of this work assignment which was to analyze the effectiveness of combustion modifications which were implemented specifically to reduce NO emissions. Rather, this unit illustrates the effect of operational considerations other than emissions. However, the results were used to quantify the effect of higher stack oxygen (and, presumably, combustion zone oxygen) on NO and heat rate. If the higher O_2 operating data for 1982 were used as a "before" condition then the 1981 results could also be interpreted as the effect of lower stack oxygen on NO and heat rate.

4.2 DATA ANALYSIS

Table 4-1 compares the results of the daily coal proximate analyses for these two time periods. On this basis there is no discernable difference in the coal properties between these two time periods. Table 4-2 presents the ultimate analyses for the coals supplied by the Eagle Butte and Belle Ayr mines. The former mine supplies 40 percent of the unit's requirement. Tables 4-3 and 4-4 summarize the NO and CO_2 analyzer certification results and compares them to the EPA specifications.

An extended version of the data reduction computer program described in Reference 2-1 was used to analyze the CEM data for the two time periods. Figure 4-1 compares the NO vs. load characteristic. As was described in Reference 2-1, this characteristic is developed by sorting the hourly averaged NO into ten load increments which span the range between the corresponding minimum and maximum hourly averaged load. Within each load "cell" the average NO and its standard deviation are calculated. Only the average value of NO is shown in Figure 4-1 and is plotted at the center of the load cell.

The 1982 data was resorted using the 1981 load range in order to facilitate the comparison of the NO vs. load characteristic. Analyses were performed to determine if there was a statistical difference in NO resulting from the higher O_2 operation in 1982. It was determined (cf. Reference 4-1) that for loads above 418 gross MWe (58 percent of rating) there was a statistically significant NO increase at the 95 percent confidence level, with these differences ranging from 5.4 to 11 percent as shown in Figure 4-2.

Figures 4-3 and 4-4 compare the load and NO probabilities, respectively, for the two time periods. The arithmetic means and median values are summarized in Table 4-5. The close agreement between the mean and median NO for both years is because the NO is nearly normally distributed as shown in Figure 4-4. Of note from all of these data was that the lower load for the 1982 time period produced a NO probability nearly identical to that for 1981, i.e., the lower loads for 1982 offset the higher NO vs. load characteristic. These results indicate that the NO probability is not a suitable measure to quantify the effectiveness of a NO reduction technology since it reflects, in part, the unit's load schedule.

The increase in stack O_2 for these time periods was approximated since the CEM was using CO_2 as the dilution correction. This approximation entailed relating O_2 to CO_2 through the use of the ultimate analyses shown in Table 4-2, properly weighted by the coal use by mine. This transformation was:

$$O_2 \text{ (\%, dry)} = 21.00 - 1.101 \cdot CO_2 \text{ (\%, dry)}$$

Figure 4-5 presents a comparison of the approximate stack O_2 as a function of load. It must be noted that any change in leakage between these dates would tend to mask the variation in combustion zone O_2. However, the comparison shown in Figure 4-5 would indicate that the stack O_2 was on the order of two percentage points higher during the 1982 time period.

The utility did indicate that there was an increase in air leakage through the ESP expansion joints during the 1982 monitoring period with respect to the corresponding 1981 period. Therefore, a portion of the higher stack O_2 (lower CO_2) was due to this leakage as well as the higher combustion air operation (to alleviate slagging tendencies). The effect of the increased leakage on total stack O_2 could not be quantified.

Figure 4-6 compares the sensitivity of NO to O_2 as a function of load for the two time periods. (The parameter ΔO_2 is interpreted as the percentage point change in O_2.) In general, operation at lower O_2 during 1981 not only resulted in a lower NO level but also reduced the sensitivity of NO to changes in O_2.

The hourly averaged net heat rate (Btu/net kW•h) was hand-sorted as a function of load (gross MWe) for the two time periods. (The data reduction computer program was subsequently extended to automate this procedure.) The result of this sorting is presented in Figure 4-7 which demonstrates the effects of O_2 operation on the net heat rate.

The data points plotted in Figure 4-7 are the mean values of heat rate at the center of the load ranges. Not shown are the corresponding standard deviations and number of points in each load range. A statistical analysis

was performed with these data to determine if there was a significant difference in the mean values. Strictly speaking the load ranges should coincide for this analysis to be valid, however, this is not usually possible. Instead, those load ranges which coincided to a high degree were analyzed.

The statistical analysis results are presented in Figure 4-8 which shows the change in heat rate between the 1981 and 1982 data as a function of load. Except at the highest load there was a statistical difference in heat rate between these dates with the percentage difference decreasing with increasing load.

In January 1982 the steam turbine back pressure increased from 2.5 in. Hg (8.4 kPa) to 3 in. Hg (10.1 kPa) due to an air leak in the steam condenser. The utility assessed that the decrease in steam turbine efficiency due to the higher back pressure was responsible for the majority of the system heat rate degradation.

KVB, however, assessed that the heat rate degradation could be due to reasons other than the higher steam turbine back pressure. Figure 4-9 shows the percentage increase in heat rate as a function of normalized steam flow for the noted increase in steam turbine back pressure. (These data were taken from a manufacturer's specifications for a reheat steam turbine designed for a back pressure of 1.5 in. Hg [5.1 kPa].) A comparison between Figure 4-8 and 4-9 would indicate that the change in heat rate could not be accounted for soley by the increased steam turbine back pressure.

The CEM data for both time periods were compared to the NO_x provisions of the 1971 and 1978 New Source Performance Standards. It was determined that there were no periods of excess emission on either a 3-hour block average or 3-hour rolling average (1971 NSPS). As shown in Figure 4-4, all of the hourly averaged NO values were less than the 1978 NSPS limitation for subbituminous coal (0.5 $lb/10^6$ Btu, 215 ng/J) for both operating conditions. These results would imply that, for the time periods analyzed, the unit could have complied completely with the 1978 NSPS on a 30-day rolling average basis.

Table 4-5 contains the mean and median values of load and NO for both operating modes.

The effect of the higher O_2 operation on fuel cost was estimated. This involved numerically integrating the heat rate vs. load results (Figure 4-7) for 1981 and 1982 to determine the mean heat rates for these time periods. These were then combined with the corresponding mean loads and with (Reference 4-2):

Delivered fuel cost	1.26\$/10^6 Btu (4.30\$/MWt)
Operating time	8030 hours/year

It was estimated that the degraded heat rate (due primarily to the higher operating O_2) was incurring an additional fuel cost of 1.2×10^6 \$/year.

4.3 CONCLUSIONS

It was concluded that higher O_2 operation of this unit produced the following:

1. Increased the NO emission factor by 5.4 (from 148 to 156 ng/J) to 11.0 percent (from 136 to 151 ng/J) for loads above 58 percent of rated generator output.

2. Increased the net heat rate (decreased efficiency) by 0 to 5.6 percent for loads above 38 percent of rated generator output.*

3. Increased the sensitivity of NO to changes in O_2.

4. Did not cause any periods of excess NO emissions with respect to the 1971 NSPS.

5. Would not have compromised the unit's potential to comply with the NO_x provisions of the 1978 NSPS.

The reason stated by the utility for the higher O_2 operation was to alleviate slagging tendencies; however, this mode of operation was not entirely successful in this respect and it was not subsequently implemented on a permanent basis. The utility has since returned to unit to the lower O_2 operating mode.

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*The increased steam turbine back pressure could have produced a 1.5 percent heat rate degradation. This value was based on a numerical extrapolation of Figure 4-9.

These data may also be interpreted as the effectiveness of lower excess air if the 1982 data is considered as the "before" condition. In this instance, the lower O_2 operation in 1981 would have resulted in a 5.1 percent reduction in NO at high load, and an integrated mean heat rate improvement of 3.2 percent.

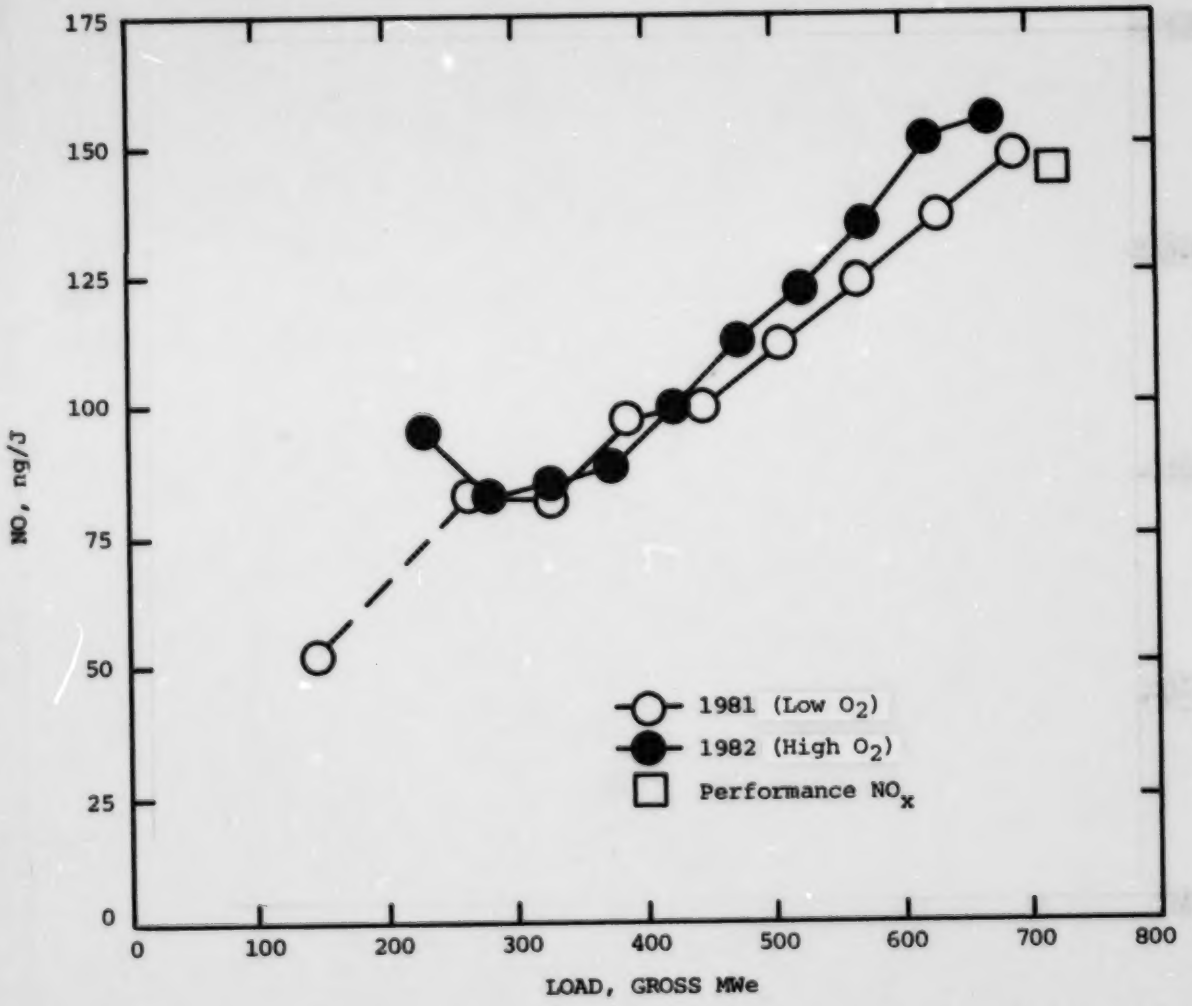

Figure 4-1. NO vs. Load Characteristic, Iowa Power & Light, Council Bluffs Unit 3

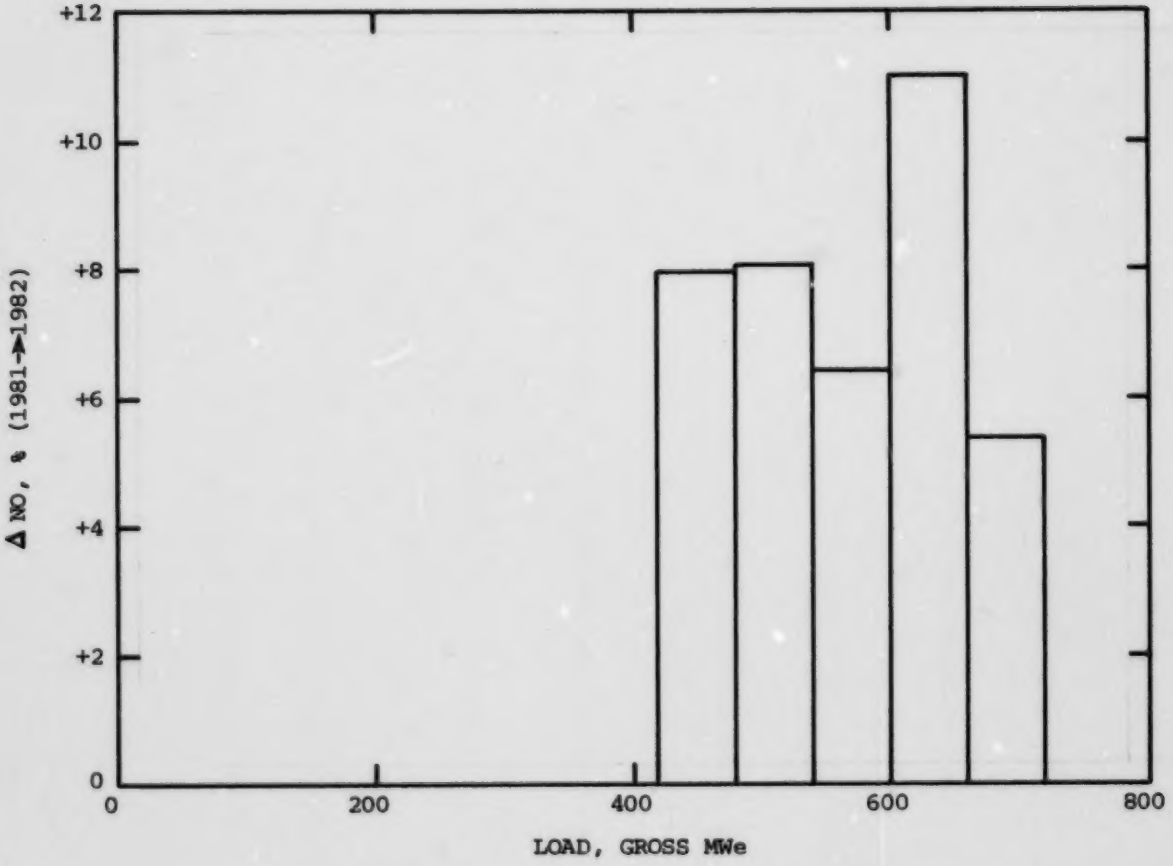

Figure 4-2. Change in NO Emissions - Iowa Power & Light, Council Bluffs Unit 3

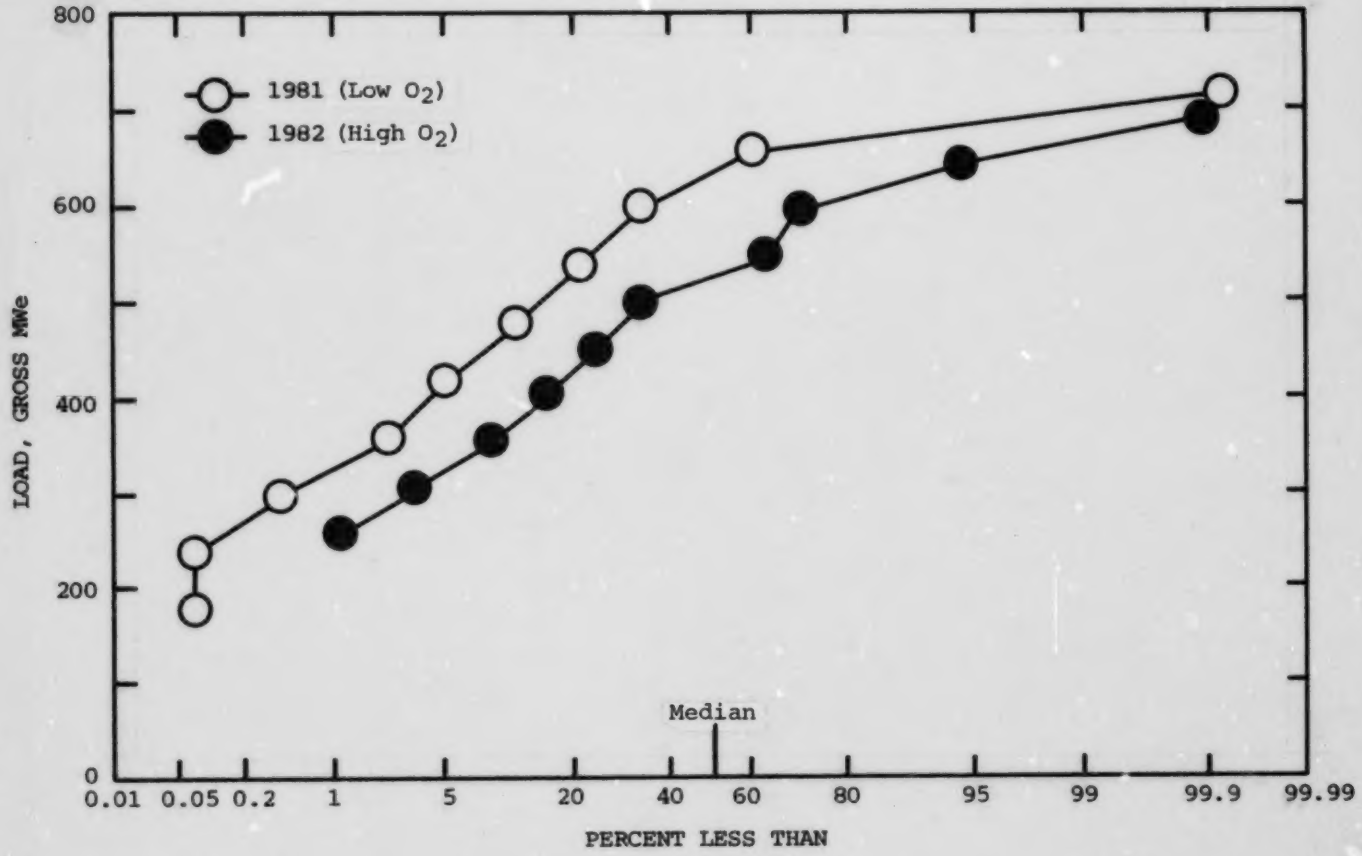

Figure 4-3. Load Probability - Iowa Power & Light, Council Bluffs Unit 3

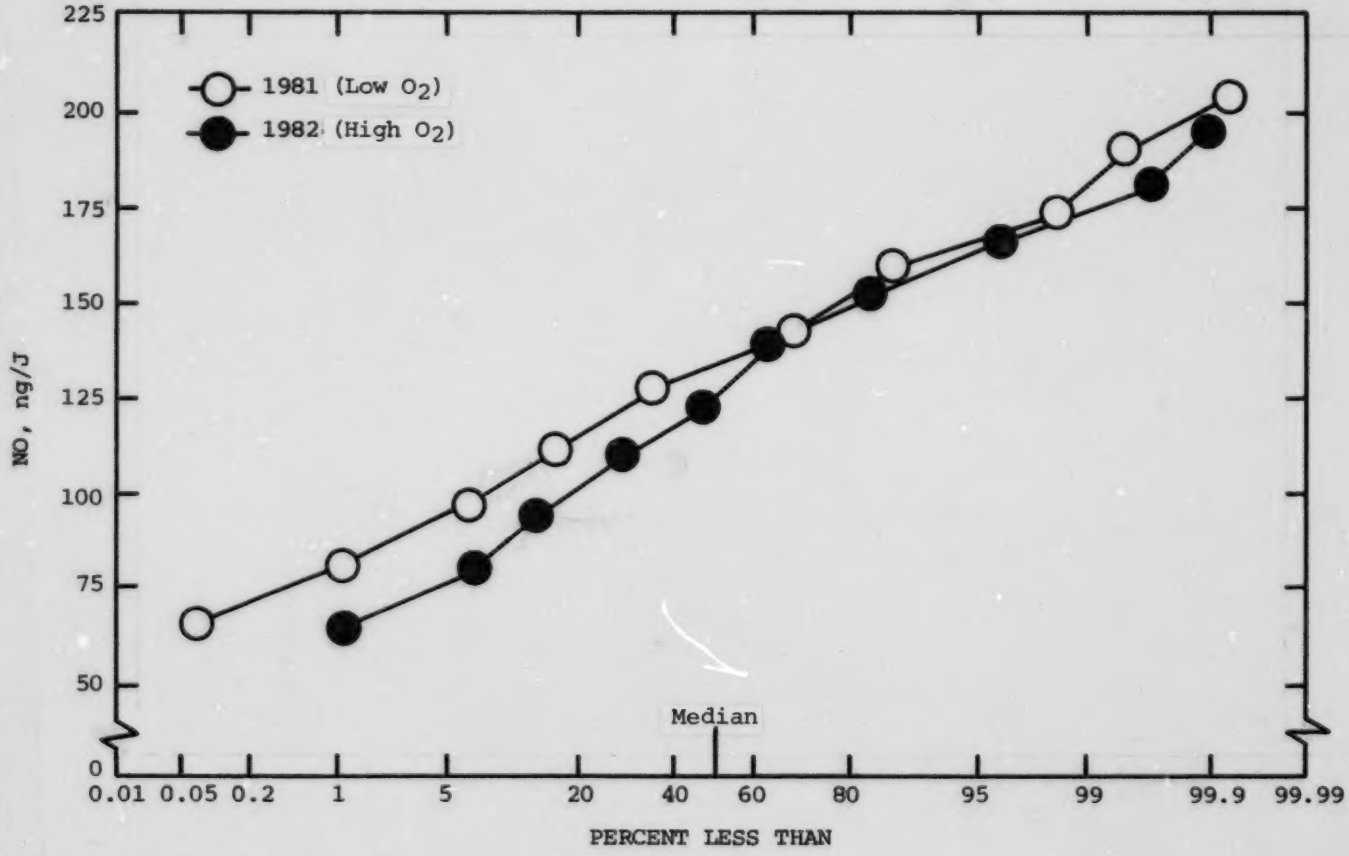

Figure 4-4. NO Probability - Iowa Power & Light, Council Bluffs Unit 3

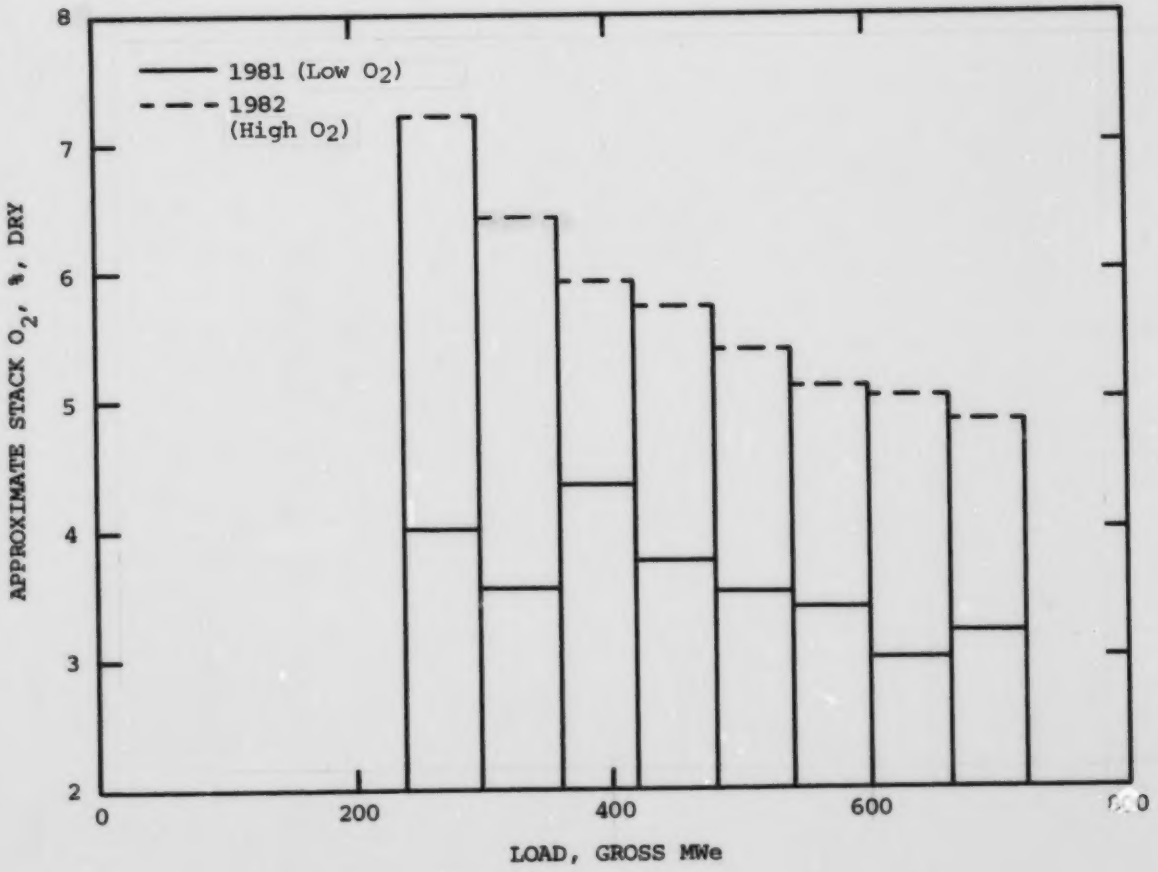

Figure 4-5. Comparison of Approximate Stack O_2 Levels - Iowa Power & Light, Council Bluffs Unit 3

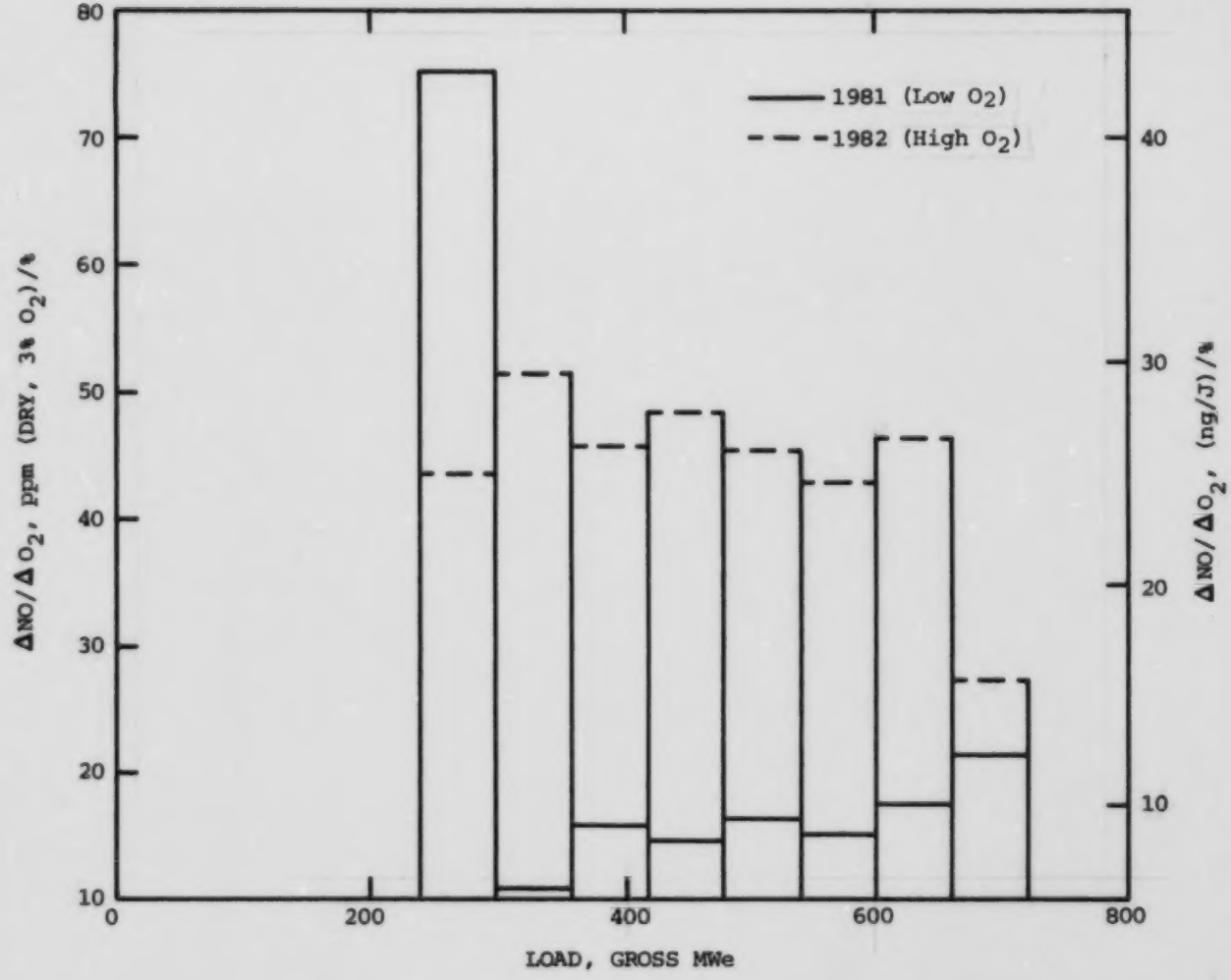

Figure 4-6. NO Sensitivity - Iowa Power & Light, Council Bluffs Unit 3

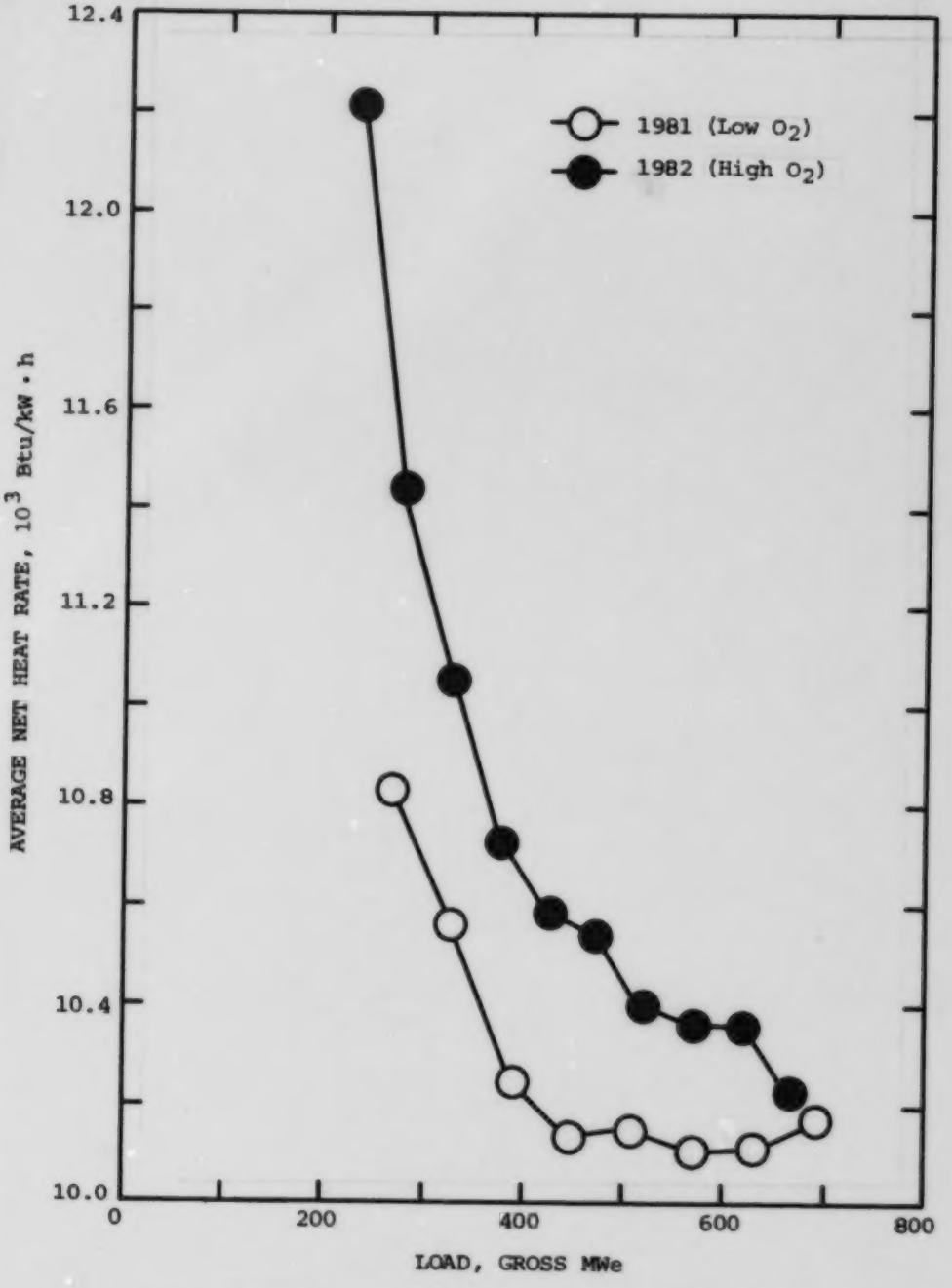

Figure 4-7. Heat Rate Comparison - Iowa Power & Light, Council Bluffs Unit 3

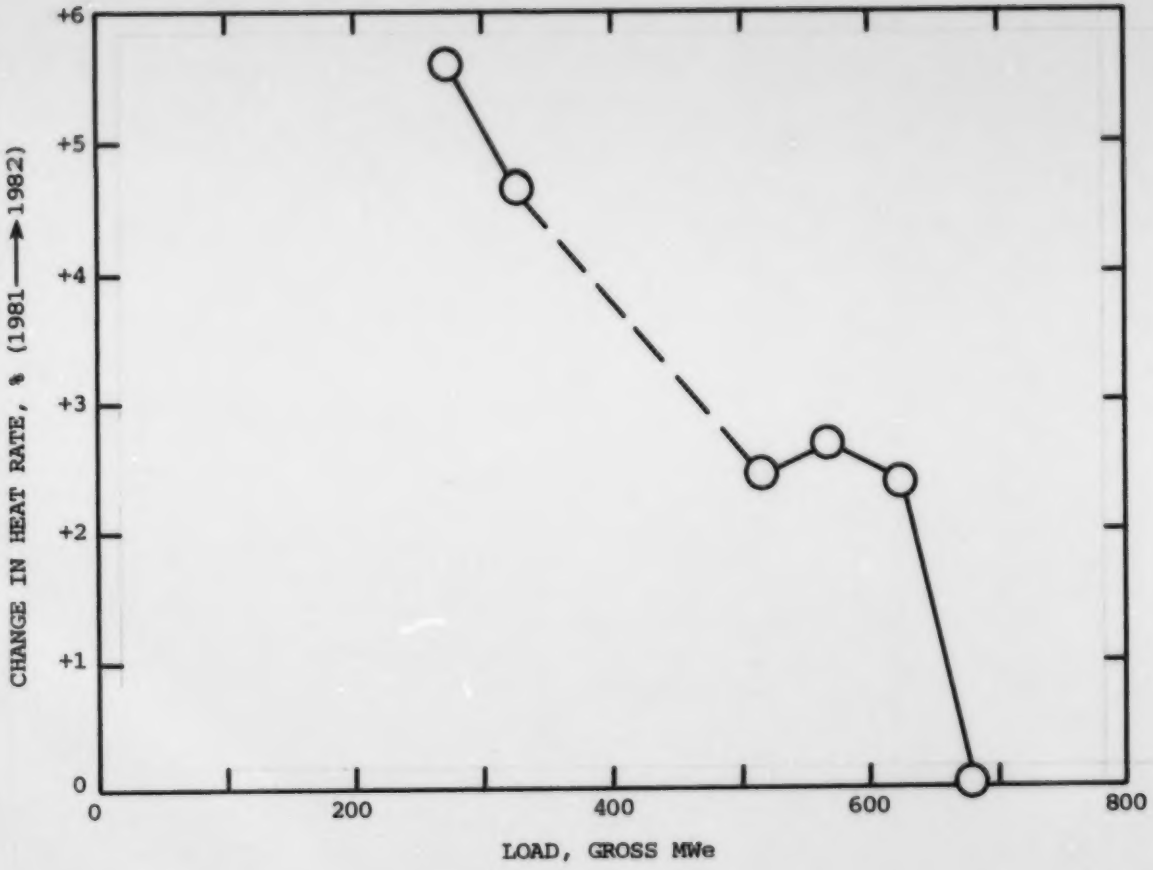

Figure 4-8. Change in Heat Rate - Iowa Power & Light, Council Bluffs Unit 3

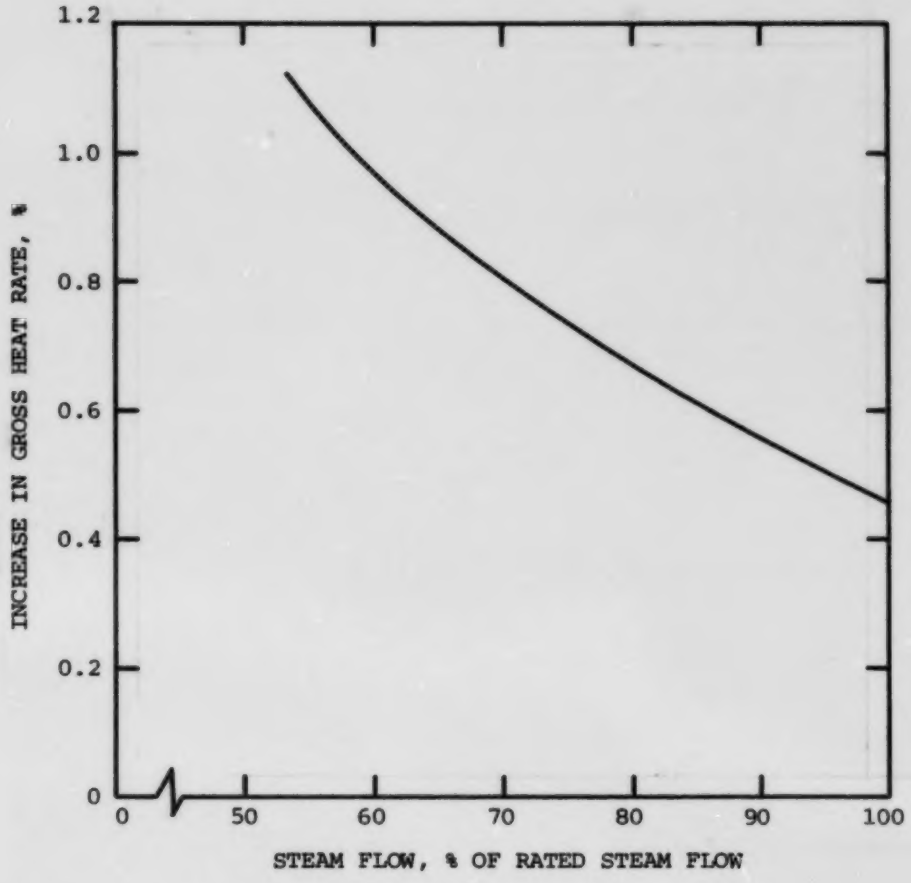

Figure 4-9. Effect on Heat Rate of Increase in Steam Turbine Back Pressure - 2.5 in. Hg ⟶ 3.0 in. Hg absolute (8.4 kPa ⟶ 10.1 kPa absolute)

TABLE 4-1. COMPARISON OF AVERAGE COAL PROPERTIES

Iowa Power & Light, Council Bluffs Station, Unit 3

Parameter	2/16/81 - 5/29/81	5/30/82 - 7/15/82
Number of Samples	151	61
Moisture, %	30.07	30.07
Sulfur, %	0.33	0.34
Ash, %	4.79	5.15
Btu/lb (kJ/kg)	8,324 (19,362)	8,309 (19,327)

TABLE 4-2. COAL ULTIMATE ANALYSES - COUNCIL BLUFFS UNIT 3

1981 DATA

Percent by Weight

	Eagle Butte Mine		Belle Ayr Mine*	
	As Received	Dry Basis	As Received	Dry Basis
Moisture	31.32	-	28.25	-
Carbon	47.11	68.60	49.69	69.25
Hydrogen	3.32	4.83	3.72	5.18
Nitrogen	0.57	0.83	0.64	0.89
Chlorine	0.02	0.03	0.05	0.07
Sulfur	0.35	0.51	0.46	0.64
Ash	4.64	6.76	5.46	7.61
Oxygen (by difference)	12.67	18.44	11.76	16.39
Btu/lb	8,113	11,813	8,643	12,046
kJ/kg	18,871	27,477	20,104	28,019

*Average of 4 analyses

TABLE 4-3. NO ANALYZER CERTIFICATION TEST RESULTS - COUNCIL BLUFFS UNIT 3

May 8-15, 1979

Parameter	EPA Specification	Test Result
Relative Accuracy	< 20%	9.53%
Zero Drift (2-Hours)	< 2% of span	*
Zero Drift (24-Hours)	< 2% of span	*
Calibration Drift (2-Hours)	< 2% of span	0.34%
Calibration Drift (24-Hours)	< 2.5% of span	0.72%
Calibration Error	< 5% (mid-range) < 5% (high-range)	1.98% 0.91%
Response Time	15 min. maximum	0.04 min.
Operational Period	168 hr. minimum	168 hr.

*Zero drift can not be simulated. Earlier models of this analyzer had no provision to simulate a zero gas condition. Later models were equipped with a gas pipe and air purge to simulate zero gas. EPA has waivered zero drift requirements.

TABLE 4-4. CO_2 ANALYZER CERTIFICATION TEST RESULTS - COUNCIL BLUFFS UNIT 3

May 8-15, 1979

Parameter	EPA Specification	Test Result
Relative Accuracy	None	7.7%
Zero Drift (2-Hours)	≤ 0.4% of CO_2	*
Zero Drift (24-Hours)	≤ 0.5% of CO_2	*
Calibration Drift (2-Hours)	≤ 0.4% of CO_2	0%
Calibration Drift (24-Hours)	≤ 0.5% of CO_2	0%
Response Time	10 min. maximum	0.10 min.
Operational Period	168 hr. minimum	168 hr.

*Zero drift can not be simulated. Earlier models of this analyzer had no provision to simulate a zero gas condition. Later models were equipped with a gas pipe and air purge to simulate zero gas. EPA has waivered zero drift requirements.

TABLE 4-5. ARITHMETIC AVERAGES AND MEDIAN VALUES

Iowa Power & Light, Council Bluffs Unit 3

720 Gross MWe

	Year	
	1981 (Low O_2)	1982 (High O_2)
Mean Load, gross MWe	607	517
% of Rated	84.3	71.8
Median Load, gross MWe	635	525
% of Rated	88.2	72.9
Mean NO, ng/J	132	124
Median NO, ng/J	133	124

SECTION 5.0

UNIT A

5.1 INTRODUCTION

The NO_x emission from this boiler was found to be in excess of the limitation contained in the 1971 New Source Performance Standard (NSPS) and the boiler manufacturer's contract. As a result, the boiler was extensively modified in order to achieve compliance with the 1971 NSPS. Continuous emission monitor (CEM) information supplied by the utility was used to estimate the long-term effectiveness of these modifications in reducing NO_x. CEM information was not available prior to the modifications.

This boiler was manufactured by Riley Stoker and was originally equipped with 24 single register Riley Flare burners. It is front-face-fired with four elevations of six burners each and uses a high-volatile "C" bituminous coal. In addition, the boiler was equipped with flue gas recirculation through the burners. The generator nameplate rating is 416.5 gross MWe.

5.2 PERFORMANCE TESTS

Tests conducted in December 1979 indicated that the NO_x at rated generator output was in excess of the limit set in the 1971 New Source Performance Standard (0.7 $lb/10^6$ Btu, 300 ng/J). Twelve Method 7 measurements yielded an average NO_x of 1.08 $lb/10^6$ Btu (464 ng/J). Further testing of the flue gas recirculation system by Riley Stoker during January 1980 demonstrated a NO_x reduction of 18 percent for flue gas recirculation rates between 13 to 18 percent. (Flue gas recirculation rate definition was not provided. The flue gas was introduced into the secondary combustion air and not the primary combustion air.)

Additional testing was performed in July and August 1981 in an effort to determine the effect of various boiler operating conditions. This effort, while achieving NO_x reductions of 24 to 31 percent, was not able to demonstrate compliance with the 1971 NSPS.

5.3 BOILER MODIFICATIONS

During the time period from September 19 to November 20, 1981, the boiler was extensively modified for the express purpose of reducing NO_x emissions. These modifications included:

1. Substituting the Riley Controlled Combustion Venturi (CCV) burner for the Flare burner.

2. Adding eight underfire air (UFA) ports below the lower burner row to control windbox pressure. These ports are manually controlled and are either fully opened or fully closed.

3. Rerouting the flue gas recirculation (for steam temperature control) to enter the furnace through the rear (unfired) wall. This would eliminate FGR as a NO_x reduction technique.

4. Bypassing up to 10 percent of the total combustion air to cool the flue gas recirculation duct when the flue gas recirculation flow was off.

Performance tests were conducted during December 1981 using EPA Method 7 with the samples obtained at the stack. The average NO_x measured during this test was 0.647 lb/10^6 Btu (278 ng/J), which demonstrated compliance with the 1971 NSPS. Thus, the above modifications reduced the NO_x by 40 percent (i.e., 1.08 vs. 0.647 lb/10^6 Btu, 464 vs. 278 ng/J). A lesser reduction (25 percent) would result if the value obtained during the August 1981 program (0.86 lb/10^6, 370 ng/J) was used.

5.4 BURNER DESIGN COMPARISON (Reference 5-1)

The Flare burners (Figure 5-1) originally installed on this boiler had single registers and were designed to be swirl stabilized to maintain intense stable combustion over a wide load range. They were installed on Riley wall-fired boilers built prior to the 1971 NSPS, and field measurements were in the 570 to 970 ppm range (approximately 0.76 to 1.3 lb/10^6 Btu, 326 to 560 ng/J).

The CCV burner, shown in Figure 5-2, is similar in design to the pre-NSPS Flare burner. The coal nozzle and coal spreader, however, have both been modified. In contrast with the Flare burner, the CCV coal nozzle is smaller

in diameter and includes a venturi section. The Flare burner multivane coal spreader has been replaced by a four bladed conical shaped spreader. In the pilot-scale burner, both spreader position and the nozzle set back position were adjustable.

The CCV burner venturi section serves to concentrate the coal in the nozzle center creating a fuel rich zone with progressively leaner mixtures toward the nozzle periphery. The conical spreader divides the coal stream into distinct layers of fuel rich and lean mixtures. The axial velocity of this primary stream is more closely matched to the secondary air velocity. This would have the effect of reducing the mixing between the primary combustion zone and the secondary air.

Secondary air swirl is controlled by a single register. Both the register and required burner opening are identical to the Flare design.

5.5 CONTINUOUS EMISSION MONITOR

The continuous emission monitor (CEM) installed on the boiler includes a Lear Siegler Model SM810 SO_2/NO and Model CM50 O_2 analyzers. The CEM system is located in the breeching to the stack, downstream of a wet SO_2 scrubber. (It is assumed that the SM810 is measuring NO only and not NO_x [= NO + NO_2].)

The CEM was certified during February 12-23, 1982 (which was after the boiler modifications). Tables 5-1 and 5-2 summarize the results of the performance tests conducted on the NO and O_2 analyzers, respectively. Of note is that the NO analyzer relative accuracy (15.3 percent) is in terms of the mass emission rate ($lb/10^6$ Btu, ng/J) and not volumetric concentration (ppm). That is, the relative accuracy was based on the analyzer readings after they had been corrected by the CM50 O_2 measurements. On a ppm basis, the NO analyzer relative accuracy was 13.5 percent.

5.6 DATA PACKAGE

The utility supplied a data package consisting of:

1. CEM hourly averaged output of NO and O_2 for the time period of September 1-30, 1982.

2. Hourly averaged unit load in gross MWe.

3. Daily coal proximate analyses for the time periods of July 26-September 14, 1981 and September 1-30, 1982. The former corresponds to the period just prior to boiler modification while the latter corresponds to the CEM data.

The utility also supplied the CEM certification report, which has already been discussed.

5.7 DATA ANALYSIS

Table 5-3 summarizes the coal proximate analyses for the time periods before and after the boiler modifications. These samples were obtained as the coal was loaded into the bunker. The coal was burned approximately one day later.

An analyses of these data indicated that at the 95 percent confidence limit, there was a statistical difference in the moisture, sulfur and heating value. The ash content, however, was not statistically different. The magnitude of the differences were -4.4, +7.2, and +1.8 percent for the moisture, sulfur and heating value, respectively.

The CEM data and the hourly averaged unit load were input to the KVB data reduction program. The basic program output of interest is the NO and O_2 sorted as a function of load. The NO vs. load characteristic can only be compared with the performance NO_x values since there is no CEM data available before the boiler modifications.

Figure 5-3 presents the boiler characteristics of NO and O_2 as a function of load.* Of note is that, in general, the NO monotonically increases with increasing load, and agrees with the performance test result at high load. This latter result implies that the unit operation had not changed significantly between the time of the performance test (December 1981) and the period analyzed (September 1-30, 1982). It is also noted from Figure 5-3 that the stack oxygen content is, in general, a monotonically decreasing function of load.

---

*The broken lines in Figure 5-3 are due to the few number of data points (2) describing NO and O_2 at the lowest load.

Figure 5-4 is the load probability as determined from the data. The median load of 316 gross MWe is 75.9 percent of the generator rated output. The NO probability (Figure 5-5) is nearly normally distributed with a median value of 225 ng/J (0.523 lb/10^6 Btu). Finally, Figure 5-6 presents the unit's diurnal characteristics, which were developed by sorting the hourly averaged NO and load by time of day.

5.8 UNIT OPERATIONAL IMPACTS

Discussions with the plant Supervisor of Operations indicated that the boiler modifications have not had a significant adverse effect on unit operation. The underfire air ports are manually opened during load increases in order to stay in compliance with the 1971 NO_x limitation. The plant personnel have learned which ports to open such that the unit is operated in a balanced condition, i.e., flow uniformity is maintained across the boiler.

The CCV burner has caused the flame to stretch-out somewhat with respect to the Flare burner. The boiler operators have estimated that the CCV burner produces a 10-25 percent longer flame than the Flare burner. Despite the longer flame, there has been no significant effect on the opposite (unfired) wall (furnace depth of 38 ft. -- 11.6 m). "Sparklers" (burning coal particles) appear at the upper levels of the unit. The unit has alway had a reheat steam temperature deficiency and a slagging problem; however, these have not been aggravated by the modifications.

5.9 COMPARISON WITH 1971 NSPS

The long-term CEM data were compared with the NO_x limitation of the 1971 New Source Performance Standard on both a 3-hour rolling average and 3-hour block average. It was determined that, on a normalized basis, the unit was in excess of the NO_x limitation for 1.3 percent and 1.9 percent for the rolling and block averages, respectively.

5.10 COMPARISON WITH 1978 NSPS

An examination of the NO probability distribution (Figure 5-5) indicates that 73.7 percent of the hourly averaged values were equal to or less

than the 1978 NSPS for bituminous coal (0.6 lb/10^6 Btu, 258 ng/J). This does not imply that the unit would be in violation of the 1978 NSPS for 26.3 percent (100.0-73.7) of the time as these periods of high NO could be averaged with periods of low emission on a 30-day basis.

5.11 CONCLUSIONS

Based on data supplied by the utility and discussions with the plant personnel, it was concluded that:

1. The boiler modifications implemented by Riley Stoker reduced NO_x emissions by 40 percent at full load with respect to the original test results.

2. The reduced NO level was maintained during normal boiler day-to-day operation.

3. The combustion modifications have not had an adverse effect on unit operation.

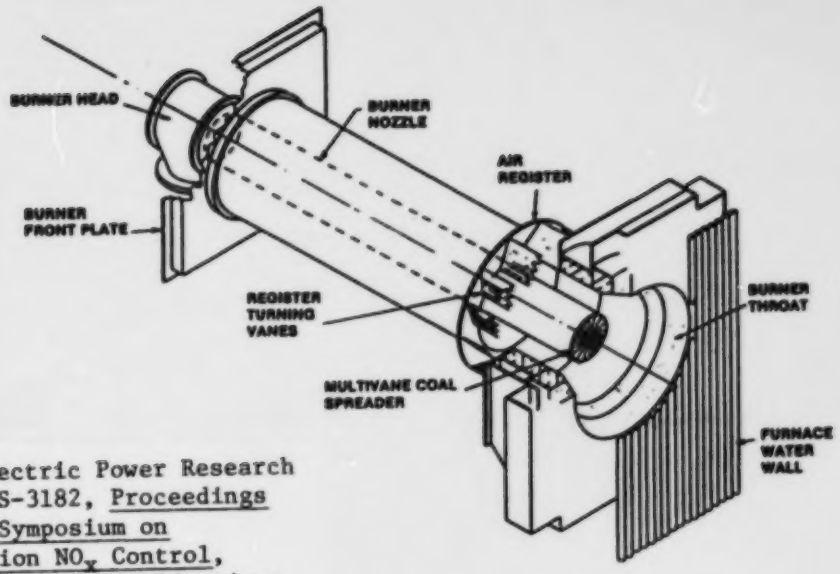

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Figure 5-1. Flare Coal Burner

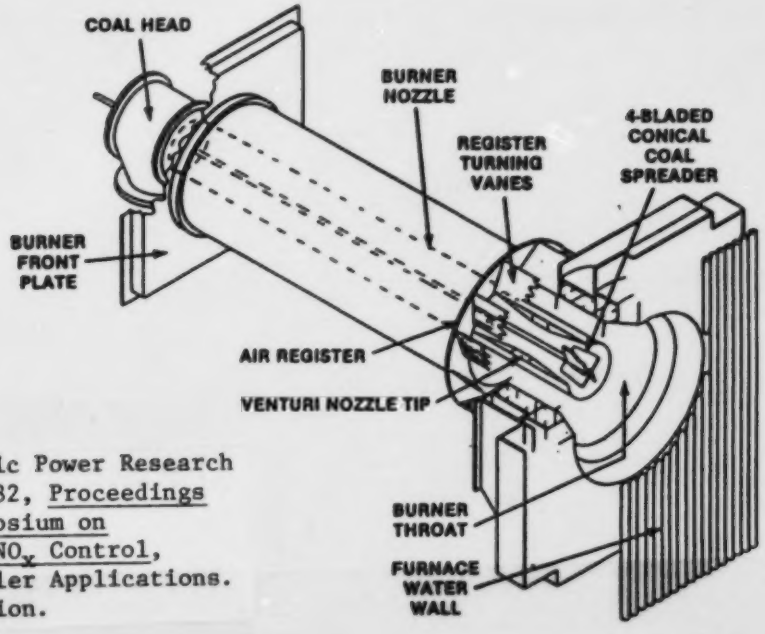

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Figure 5-2. Controlled Combustion Venturi (CCV) Burner

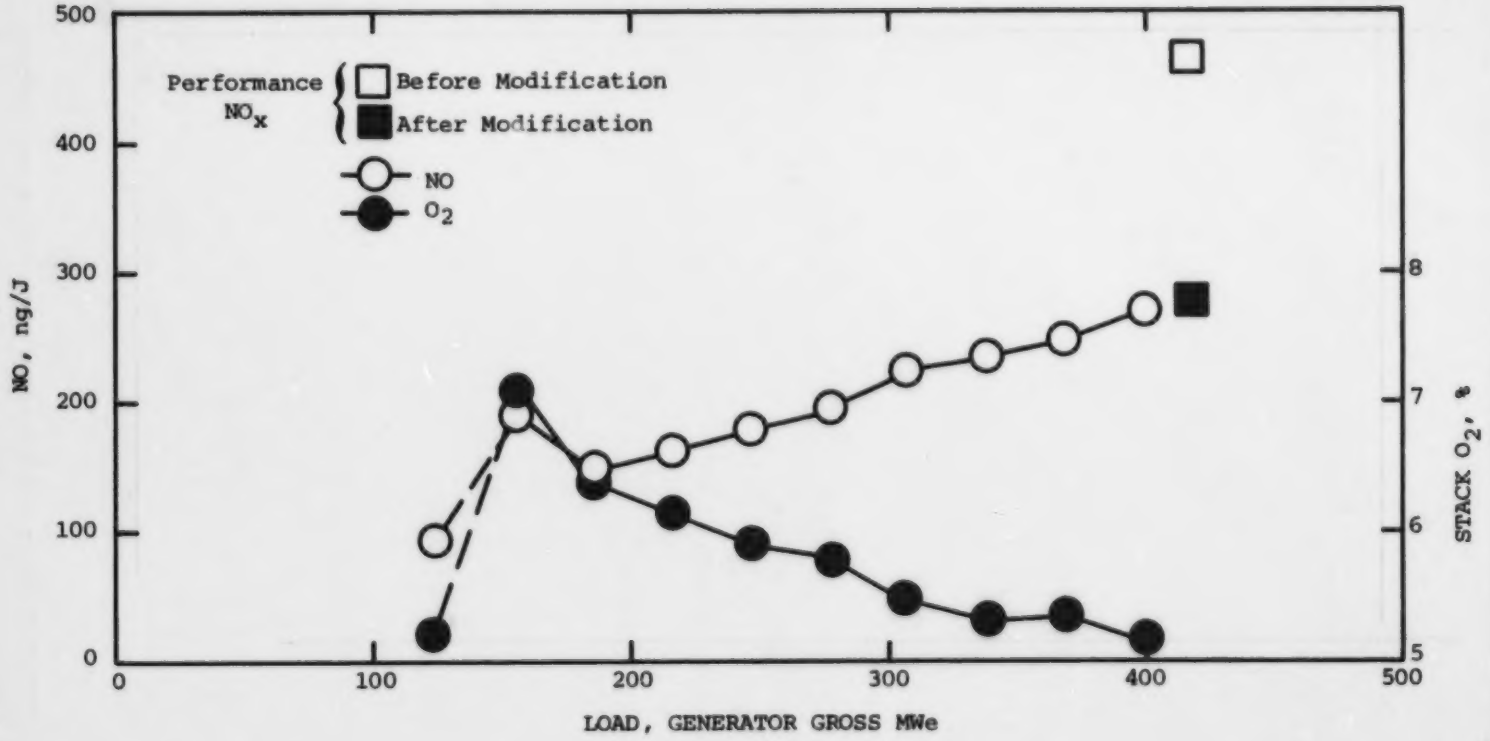

Figure 5-3. NO and O_2 vs. Load - Unit A

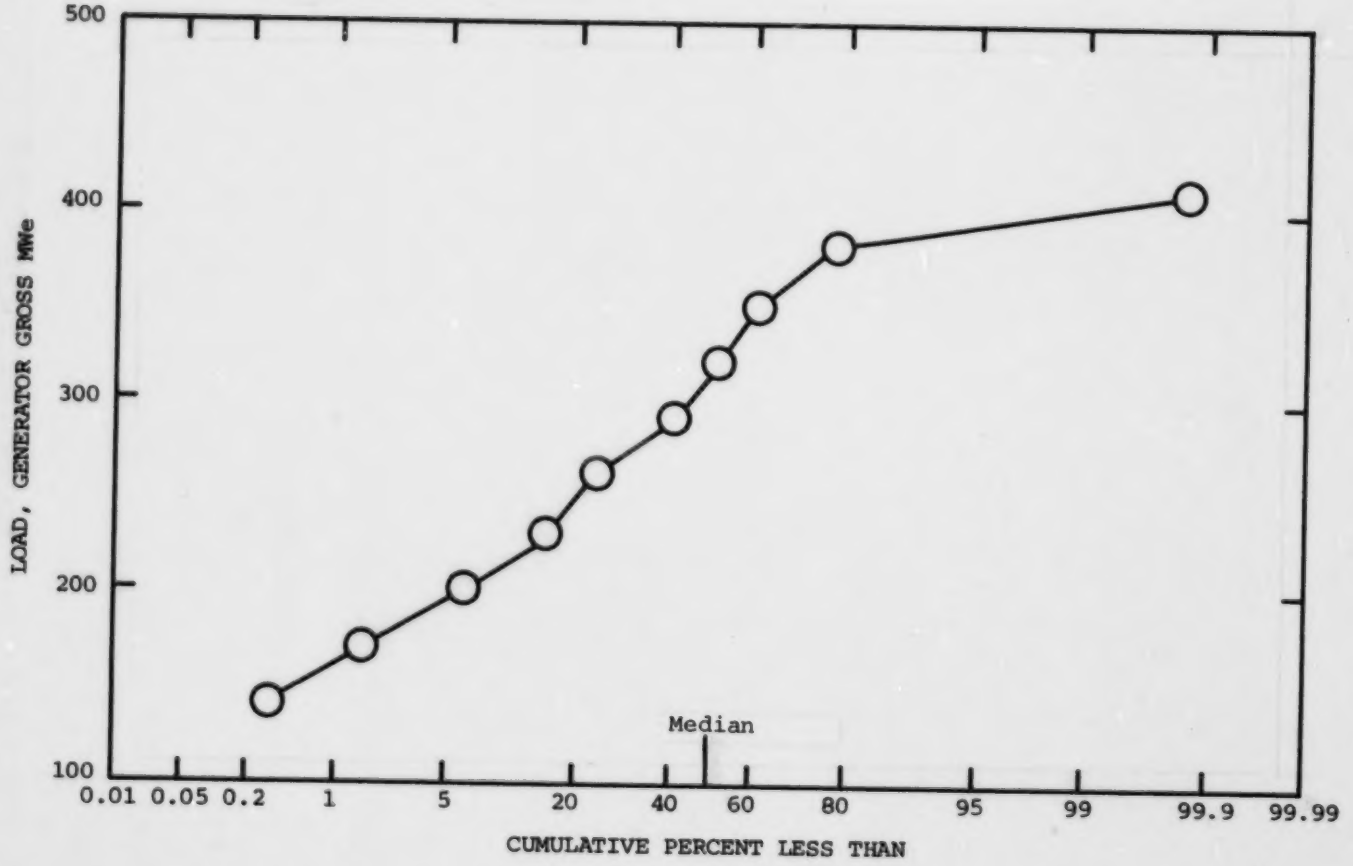

Figure 5-4. Load Probability - Unit A

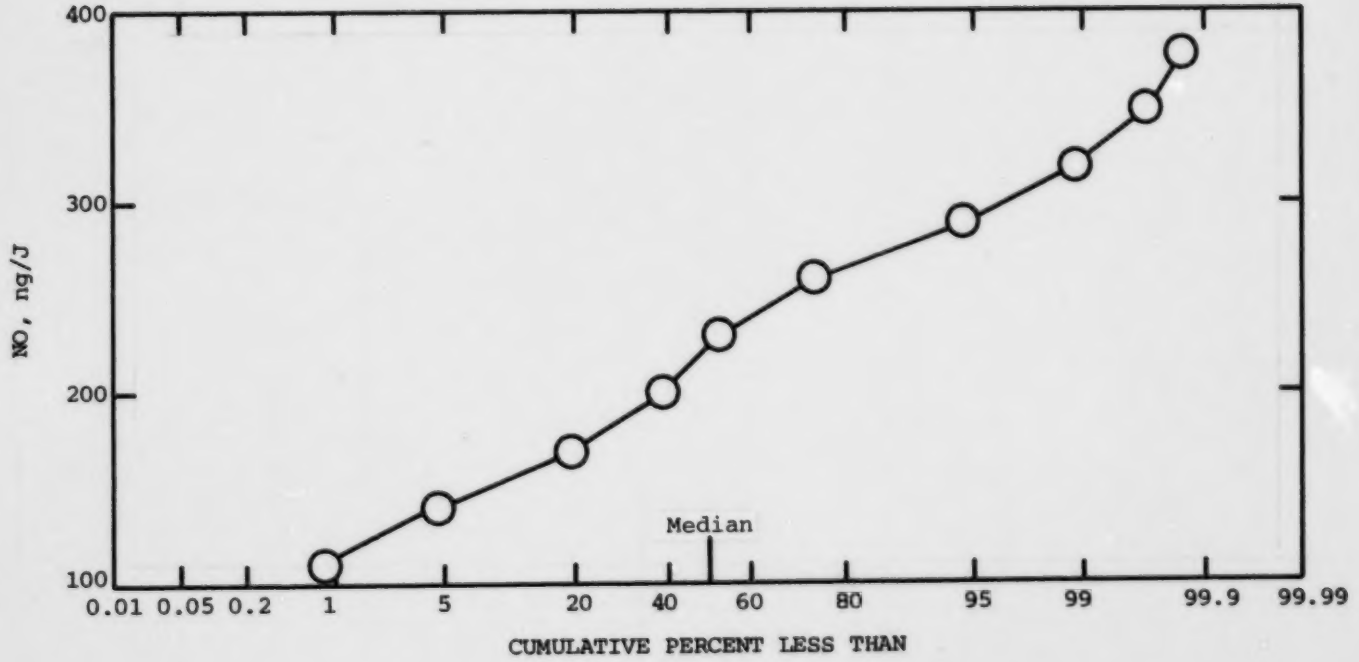

Figure 5-5. NO Probability - Unit A

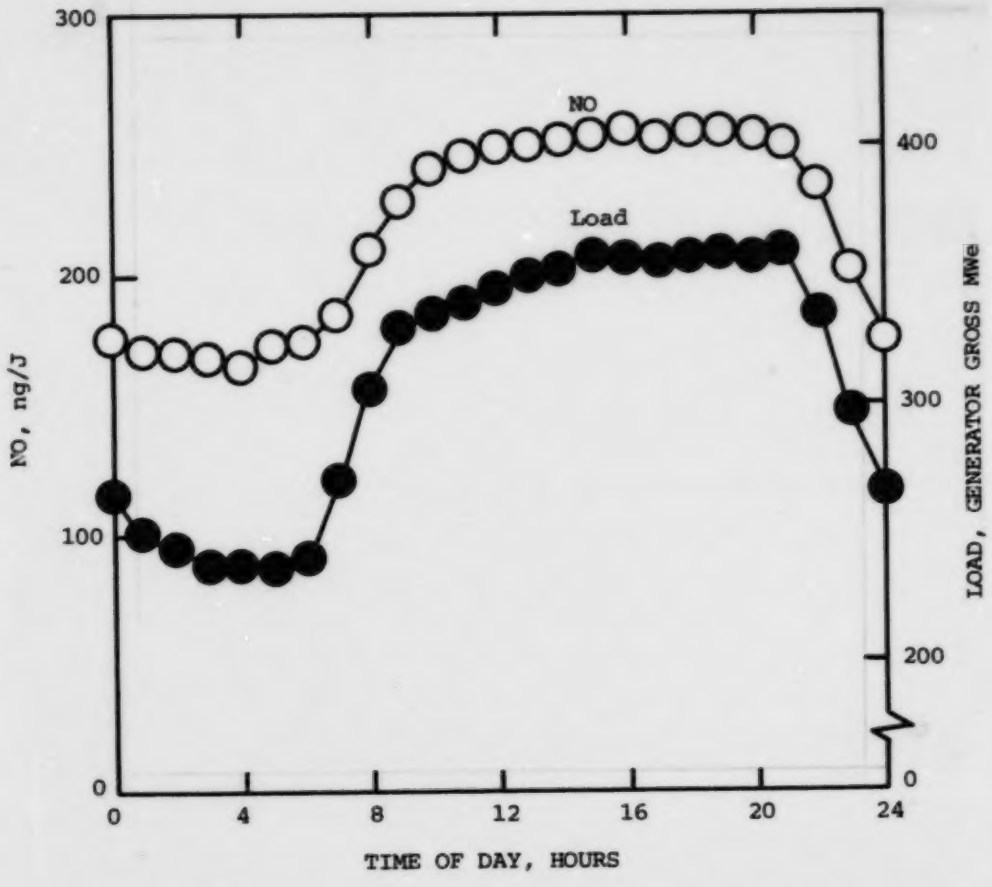

Figure 5-6. Diurnal Characteristics - Unit A

TABLE 5-1. UNIT A NO ANALYZER CERTIFICATION RESULTS

Parameter	EPA Specification	Test Result
Calibration Error	< 5%	2.8% Mid
	< 5%	1.3% High
Response Time	< 15 Minutes	3.0 Minutes
Conditioning Period	> 168 Hours	168 Hours
Operational Test Period	> 168 Hours	168 Hours
Zero Drift (2-Hours)	< 2%	0.0%
Zero Drift (24-Hours)	< 2%	0.0%
Calibration Drift (2-Hours)	< 2%	0.0%
Calibration Drift (24-Hours)	< 2.5%	0.0%
Relative Accuracy	< 20%	15.3

TABLE 5-2. UNIT A O_2 ANALYZER CERTIFICATION RESULTS

Parameter	EPA Specification	Test Result
Zero Drift (2-Hours)	< 0.4% O_2	0.00%
Zero Drift (24-Hours)	< 0.5% O_2	0.01%
Calibration Drift (2-Hours)	< 0.4% O_2	0.00%
Calibration Drift (24-Hours)	< 0.5% O_2	0.07%
Response Time	< 10 Minutes	0.2 Minutes
Conditioning Period	> 168 Hours	168 Hours
Operational Test Period	> 168 Hours	168 Hours

TABLE 5-3. UNIT A PROXIMATE ANALYSES
(As Bunkered)

	July 26-Sept. 14, 1981	Sept. 1-30, 1982
No. of Samples	51	26
Mean Moisture, %	16.45	15.73
Moisture Standard Deviation, %	1.60	0.54
Mean Sulfur, %	3.21	3.44
Sulfur Standard Deviation, %	0.27	0.11
Mean Ash, %	8.78	8.63
Ash Standard Deviation, %	0.56	0.31
Mean Heating Value, Btu/lb (kJ/kg)	10,515 (24,458)	10,709 (24,909)
Heating Value Std. Dev., Btu/lb (kJ/kg)	223 (519)	96.2 (224)

SECTION 6.0

UTAH POWER AND LIGHT, HUNTER STATION UNIT 2

6.1 INTRODUCTION

Exxon Research and Engineering Company, under contract to the United States Environmental Protection Agency, has been investigating the long-term effect of low-NO_x operation on fireside corrosion in pulverized-coal-fired utility boilers. KVB, under subcontract to Exxon, has provided the supporting long-term continuous emission monitoring data.

This unit, manufactured by Combustion Engineering, has been extensively modified in order to reduce NO_x emissions. KVB data, obtained during two separate post-modification 30-day periods, were analyzed to determine the effect of normal day-to-day unit operation on NO. Full-load, short-term NO_x tests conducted by Exxon* prior to the modifications were used here along with the KVB data to assess the effectiveness of the modifications. Adequate data from the unit's continuous emission monitor (CEM) were not available for the pre-modification time period. A comprehensive evaluation of the combustion modifications, performed under EPA Contract No. 68-02-2696, will be presented in Exxon's final report.

6.2 UNIT MODIFICATIONS

The following modifications were implemented on this unit:

1. Variable offset between auxiliary air ports and coal nozzles.
2. Flame holder added to coal nozzles.
3. Overfire air port opening schedule.

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*The Exxon tests were in terms of NO_x (=NO + NO_2). The KVB continuous emission monitoring results were in terms of NO only.

Items 1 and 2 comprise the "Low-NO_x Concentric Firing System (LNCFS)" and refers to the use of a variable offset between the coal and auxiliary air nozzles.

The LNCFS was implemented by adding a yaw adjustment to the auxiliary air nozzles (Figure 6-1) so that they could be directed tangent to a larger diameter circle in the center of the furnace (Figure 6-2). (The minimum offset angle of 17° shown in Figure 6-2 was subsequently changed to 8°.) Figures 6-3 and 6-4 compare the original and modified windbox configurations. Also shown are the five elevations of coal nozzles. The vertical adjustment capability of the coal and auxiliary air nozzles (for steam temperature control) was retained.

One of the original modifications to the boiler was a blocking off of a significant fraction of the free area in the fuel air compartments in order to force more air through the auxiliary air compartments. Following the March 1982 series of post-modification tests by Exxon and CE, it was decided that a further optimization of the LNCFS was necessary to stabilize the flame front even closer to the coal nozzle tip. Therefore, a second generation LNCFS was developed in which divergent coal nozzle tips (flame holders) were installed to direct the fuel air away from the primary air and fuel jets.

The overfire air ports, which had previously been closed, were now scheduled to begin to open when the load reached 250 gross MWe, and be fully open at 350 gross MWe, with a linear ramp between these loads. This schedule was under manual control of the operators. (The unit's generator was rated at approximately 425 gross MWe.)

6.3 PRE-MODIFICATION TESTING (Reference 6-1)

Short-term pre-modification testing at full-load was conducted by Exxon during August 1981 to characterize the NO_x emissions over the parameter range shown in Table 6-1. For these short-term characterization tests, Exxon used standard calibration methods, but not the rigid Federal Reference Method certification procedures used by KVB during the 30-day continuous monitoring

tests. (The unit NO_x performance test, as required by the 1971 New Source Performance Standard, was conducted on August 5, 1980. The result was 0.59 lb/10^6 Btu -- 254 ng/J.)

The results of the Exxon pre-modification testing at full-load are summarized as follows:

1. With all parameters at their typical operating set point, NO_x was 460 ppm (dry, at 3 percent O_2) which is approximately 0.61 lb/10^6 Btu (262 ng/J). This value is in close agreement with the result of the unit performance test.

2. A one percentage point increase in flue gas oxygen caused the NO_x to increase by 45 ppm over the entire test range (2.4 to 5.8 percent O_2).

3. The use of overfire air (OFA) reduced NO_x emissions by about 70 ppm when the OFA tilt was horizontal and by approximately 100 ppm when the OFA tilt was set to +30 degrees.

4. A reduction in the amount of fuel air (fuel compartment secondary air) resulting from the closure of the fuel air dampers from 100 percent to 50 percent yielded NO_x reductions of approximately 50 to 60 ppm.

5. The results from the burner tilt variation tests without overfire air yielded a trend of increasing NO_x (about 48 ppm) with increasing burner tilt (from -10° to +10°). However, it should also be noted that other synergistic effects often camouflage burner tilt trends, especially for non-overfire air operation.

6.4 CONTINUOUS EMISSION MONITORING

Instrumentation

To date, KVB has performed two 30-day continuous emission monitoring programs on this unit. These tests were performed following installation of the second generation LNCFS. The periods covered were:

October 23 - December 2, 1982 (652 data points)
April 8 - May 14, 1983 (645 data points)

These periods are hereafter referred to as 1982 and 1983, respectively.

A portable extractive package containing the following analyzers was used:

Emission Species	Manufacturer	Measurement Method	Model No.
Nitrogen Oxides	Thermo Electron	Chemiluminescent	10 AR
Oxygen	Thermox	Zirconium oxide	III
Carbon Dioxide	Horiba Instrument	NDIR	PIR-2000
Carbon Monoxide	Horiba Instrument	NDIR	PIR-2000

The gas sample was drawn from one of the two ducts at a location between the economizer and air heater. The analyzers were completely certified during each period, as per EPA Performance Specifications 2 and 3 (40 CFR 60, Appendix B), and the NO_x relative accuracy was also determined at the conclusion of each period (four determinations total).

Tables 6-2 and 6-3 present the results of the monitor certification tests. In all instances, the EPA specification requirements were achieved. Also noted are the individual NO analyzer relative accuracy determinations.

Coal proximate and ultimate analyses are summarized in Table 6-4 for both 30-day post-modification continuous monitoring periods. The samples were collected by KVB. The coal is ranked as a high-volatile "B" bituminous. The utility supplied the results of 58 coal proximate analyses conducted during August 1981, which was <u>just prior</u> to the boiler modifications. The results summarized in Table 6-5 were then compared to those obtained during both continuous emission monitoring periods (Table 6-4) to determine if any of the coal parameters had changed. It was determined that, at the 95 percent confidence limit, there was no statistical difference in moisture, ash, fixed carbon, heating value and sulfur. However, the mean values of the volatile matter were different, with the difference being 5.2 percent. CE also furnished two analyses for August 1981 which are shown in Table 6-6.

6.5 DATA ANALYSIS

The hourly averaged values of NO, O_2 and load (gross MWe) were analyzed by the KVB-developed data reduction computer program. (An earlier version of this program is described in Reference 2-1.) Appendix B in References 6-2 and 6-3 present the 15-minute averaged gaseous emission measurements obtained by KVB during the two long-term continuous monitoring periods. These 15-minute averages were combined to produce the one-hour averages required by the data reduction computer program. These references also contained the unit load in gross MWe. The key results obtained from this program are:

1. Boiler characteristics of NO and O_2 vs. load
2. Load probability
3. NO probability
4. NO sensitivity to O_2

Each of the two monitoring periods were separately analyzed to determine if the unit operation was consistent between the two periods.

Figure 6-5 compares the NO vs. load characteristic for the two monitoring periods. (The numbers above the bars in Figure 6-5 identify the load cell.) It must be noted that the 1983 data contained only five points with loads greater than 345 gross MWe. Therefore, the results shown for load cells 8-10 are not statistically defined. (The same qualification applies to Figure 6-6.) The NO vs. load characteristic for 1982 shows a trend of increasing NO with decreasing load. This trend may be due the design of Combustion Engineering units, i.e., as the load is decreased, the percent excess air automatically increases, and the percent overfire air manually decreases. These two effects are responsible for the observed NO vs. load trend especially for loads less than 250 gross MWe. (The overfire air ports were scheduled to be closed below this load.) There was no clear trend in the NO vs. load characteristic for the 1983 data.

An analysis (cf. Reference 4-1) of these data indicated that, at the 95 percent confidence limit, there was a statistically significant difference in NO for load cells 1, 2, 5 and 6*. The analysis also showed that the 1983 results were lower than those for 1982 for these load cells by 24, 18, 4.4 and 12 percent, respectively. A similar analysis of the O_2 vs. load characteristic (Figure 6-6) showed a statistically significant difference for load cells 2-7. The 1983 results for O_2 were lower than those for 1982 with the differences being 1.2, 1.2, 1.2, 1.6, 2.7 and 2.1 percentage points for load cells 2-7, respectively. Thus, the lower O_2 operation during 1983 could be the primary cause of the lower NO.

A comparison between the NO_x measured during the unit performance test (0.59 lb/10^6 Btu, 254 ng/J) and the high load (395-421 gross MWe) NO data for 1982 (13 data points) would indicate a 39 percent reduction in emissions. (As previously discussed there were insufficient high load data for 1983 to make a similar comparison.) This reduction can be attributed to overfire air usage, lower excess oxygen levels, the effects of the LNCFS plus other synergistic effects.

As was previously discussed, an overfire air port opening schedule had been developed for this unit. This schedule was manually controlled by the operators and it was found that adherence to the schedule was operator dependent. It must be mentioned that the overfire air port opening schedule was new and unfamiliar to the operators during the first 30-day continuous monitoring test. This may explain the "operator dependent" overfire air usage. In addition, the overfire air nozzle tilt was changed by Combustion Engineering just prior to the 1983 monitoring period. The original tilt of 10° above the horizontal was changed to 10° below the horizontal. The overfire air nozzle tilt, once set, was not varied with load.

The effect of this change in overfire air tilt on NO_x has not been completely characterized for Hunter Unit 2 operating with the LNCFS. This is due, in part, to the dynamic nature of this boiler wherein a change in a NO_x

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*The significance test involves the mean values, standard deviations and number of data points. It would not be correct to judge significance solely on the basis of a plot of the mean values.

reduction strategy occasionally results in a large O_2 imbalance between the two flue gas ducts.

Previous results obtained by Combustion Engineering (Reference 6-5) have shown a NO_x increase of 58 ppm (0.077 lb/10^6 Btu -- 33 ng/J) for a 20° reduction in the relative angle between the overfire air and coal nozzles. These results were obtained on tangentially fired units without the LNCFS, therefore, this NO_x sensitivity to overfire air tilt may not be appropriate for Hunter Unit 2.

Indeed, preliminary results obtained on Hunter Unit 2 (Reference 6-6) have shown NO_x increases ranging from 0 to 55 ppm (0 to 0.073 lb/10^6 Btu -- 0 to 31 ng/J) for a 20° reduction in this relative angle. This variability is due to the synergistic effects of the combustion controls on NO_x reductions, caused by the LNCFS.

Figures 6-7 and 6-8 compare the load and NO probabilities for 1982 and 1983, respectively. None of these are expressible exactly by a normal distribution. The median and mean values of load, NO and O_2, are summarized in Table 6-7. An examination of the NO values clearly indicates that an operational change(s) had occurred between the two monitoring periods. The operational changes that actually took place can be summarized as follows (Reference 6-5):

> Following Exxon's characterization tests in Sept/Oct 1982, the operators were given the task of running the unit with a new automatic oxygen vs. load profile. They were instructed to manually follow an overfire air vs. load profile, plus they were instructed to balance the flue gas duct oxygen levels by whatever means necessary to assure continued operation. Due to operator unfamiliarity with the new systems, there were very inconsistent oxygen levels and overfire air usage during the 1982 test.
>
> Prior to the 1983 test, the boiler was set at conditions which would minimize an oxygen imbalance while maintaining significant NO_x reductions. Three days into the test, a large oxygen imbalance appeared. It was decided by UP&L that it would be better to reduce the oxygen imbalance by lowering the overfire air tilts (from +10° down to -10°) and thus, increase NO_x somewhat rather than require the operators to make constant operational corrections.

The significantly lower O_2 for the 1983 monitoring period was sufficient to reduce the mean NO by 6 percent despite the lower overfire air nozzle tilt which would have increased NO. The lower O_2 could be attributed to a reduction in the imbalance between the two flue gas ducts.

The long-term CEM data for both time periods were compared with the NO_x limitation in the 1971 New Source Performance Standard (0.7 $lb/10^6$ Btu, 300 ng/J). It was determined that there were no periods of excess emission on either a 3-hour rolling average or 3-hour block average basis.

6.6 CONCLUSIONS

Modifications implemented on this unit have:

1. Produced a NO_x reduction of approximately 39 percent at high load. This reduction is based on the 1971 NSPS performance test and high load data obtained by KVB during the 1982 monitoring test.

2. This reduction can be attributed to a combination of overfire air usage, lower O_2 levels, the LNCFS plus other synergistic effects.

3. Long-term continuous emission monitoring conducted during two different post-modification time periods has shown some degree of operational variability, e.g., a significantly lower economizer O_2 was measured during the second monitoring period.

4. These operational differences, including a change in the overfire air nozzle tilt, caused a statistically significant difference in NO at certain regions within the unit's normal load range.

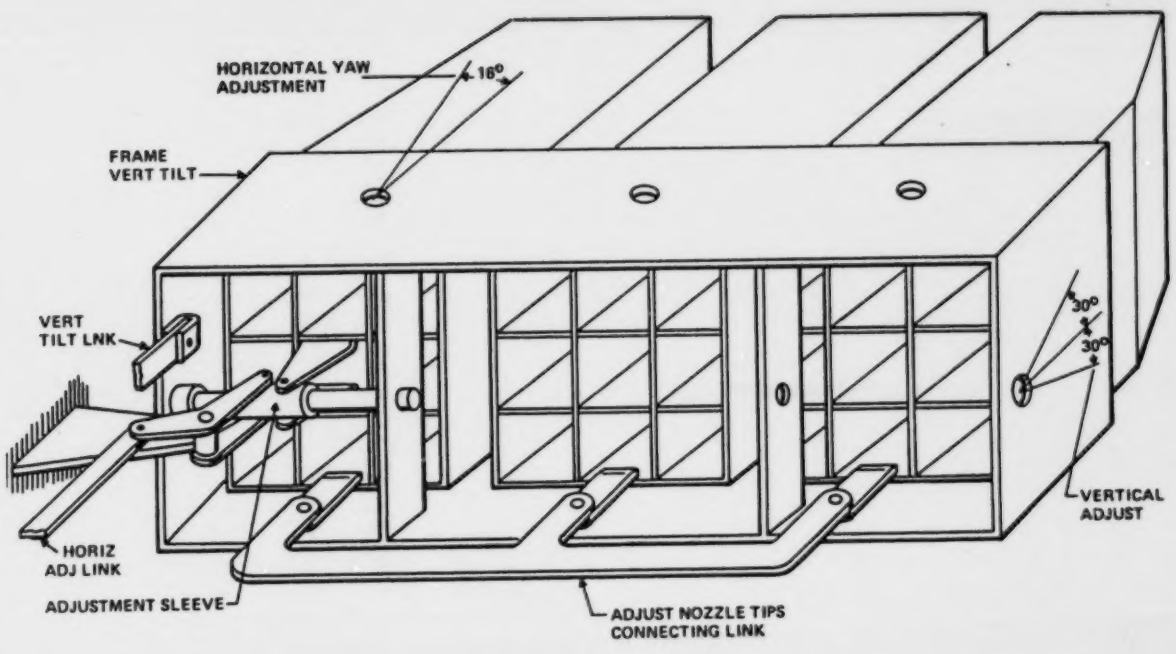

Figure 6-1. Auxiliary Air Nozzle With Yaw Adjustment

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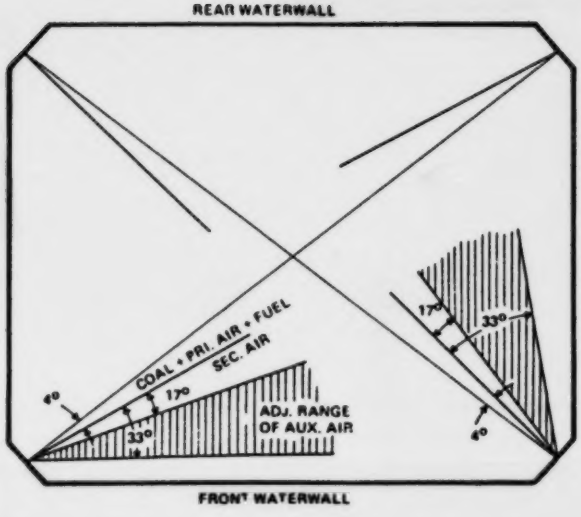

Figure 6-2. Injection angles for fuel and air--Utah Power & Light Company. (The 17° minimum offset angle subsequently changed to 8°.)

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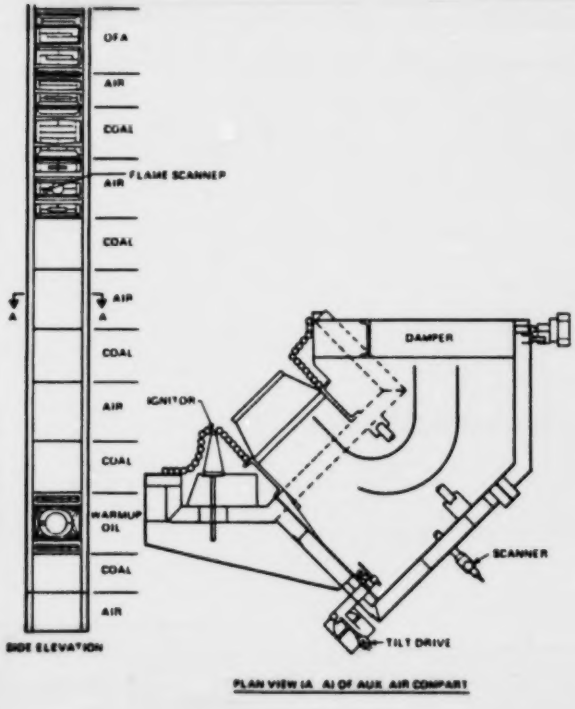

Figure 6-3. Original windbox at Hunter 2.

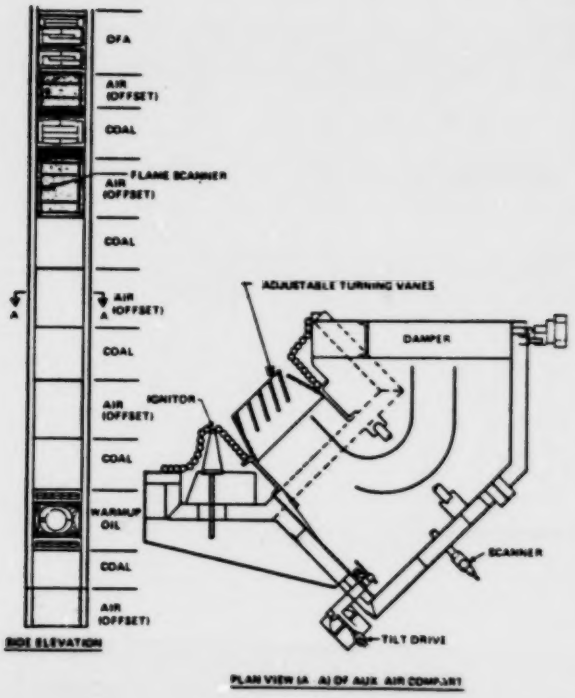

Figure 6-4. Modified windbox at Hunter 2.

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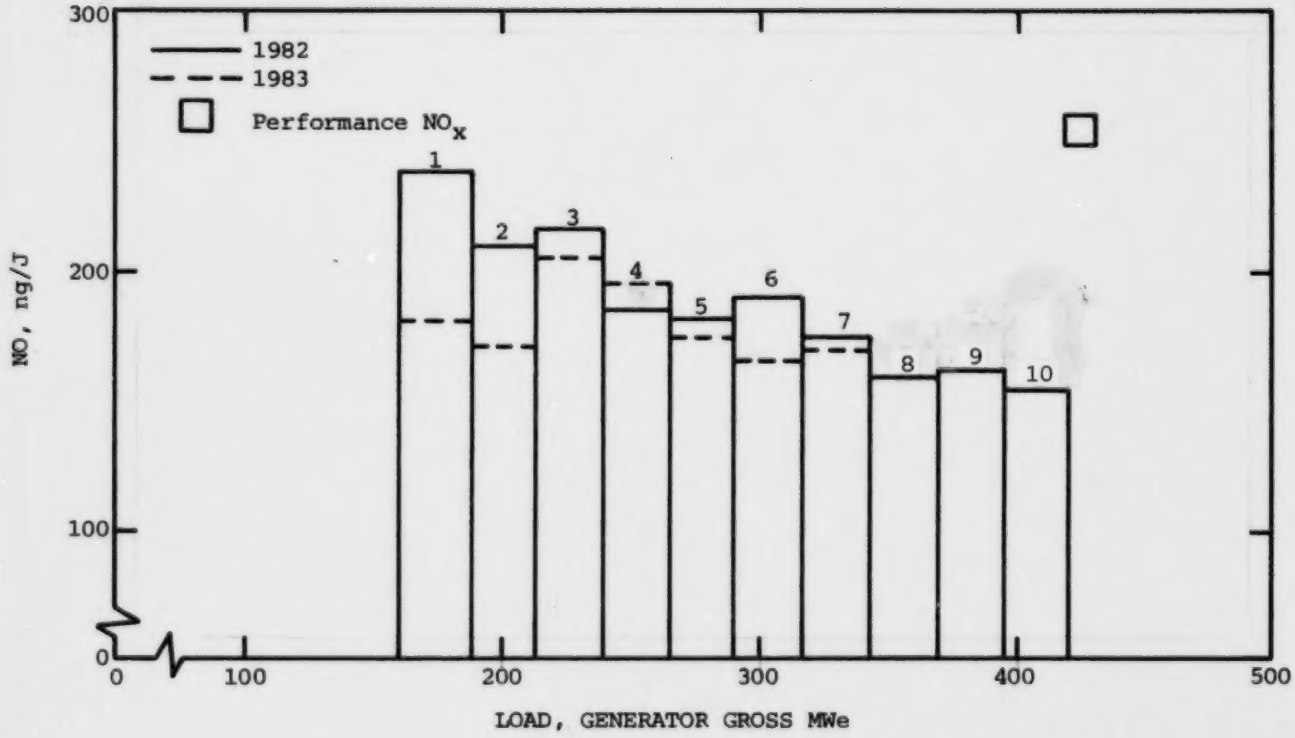


Figure 6-5. NO Comparison - Utah P&L, Hunter Station Unit 2

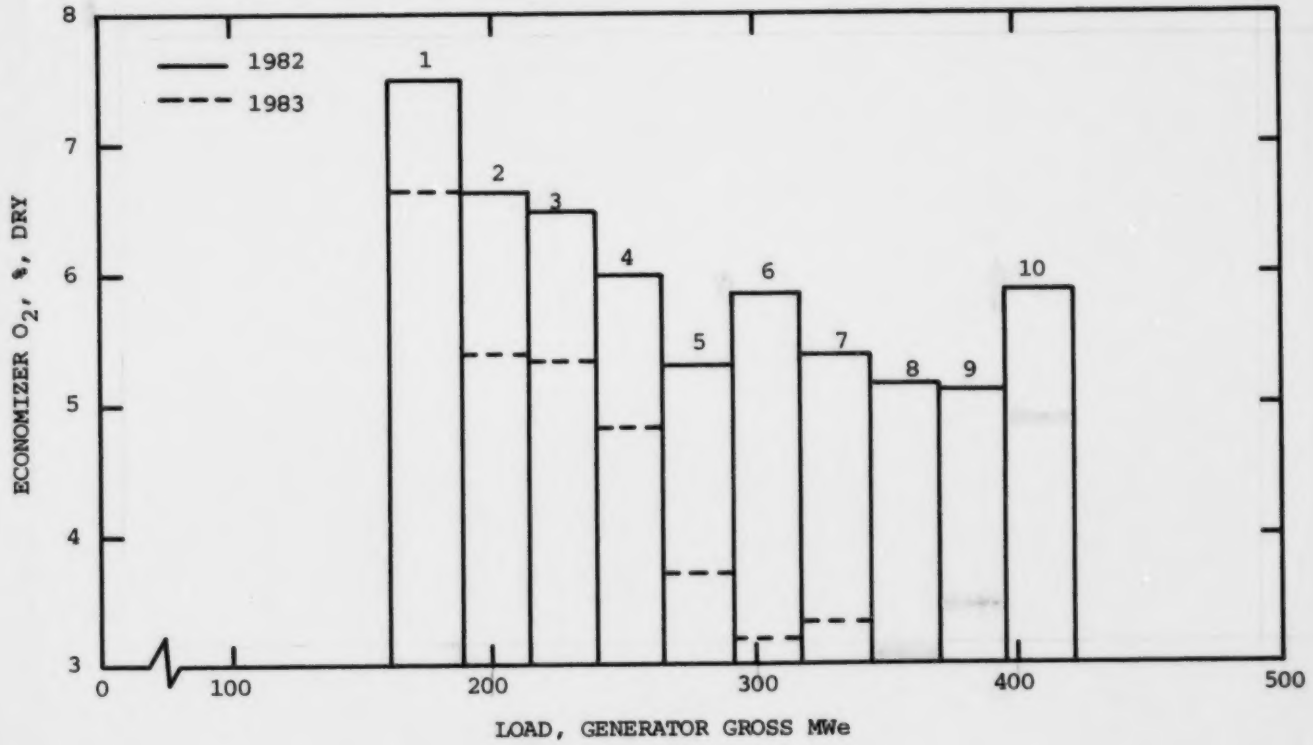


Figure 6-6. O_2 Comparison - Utah P&L, Hunter Station Unit 2

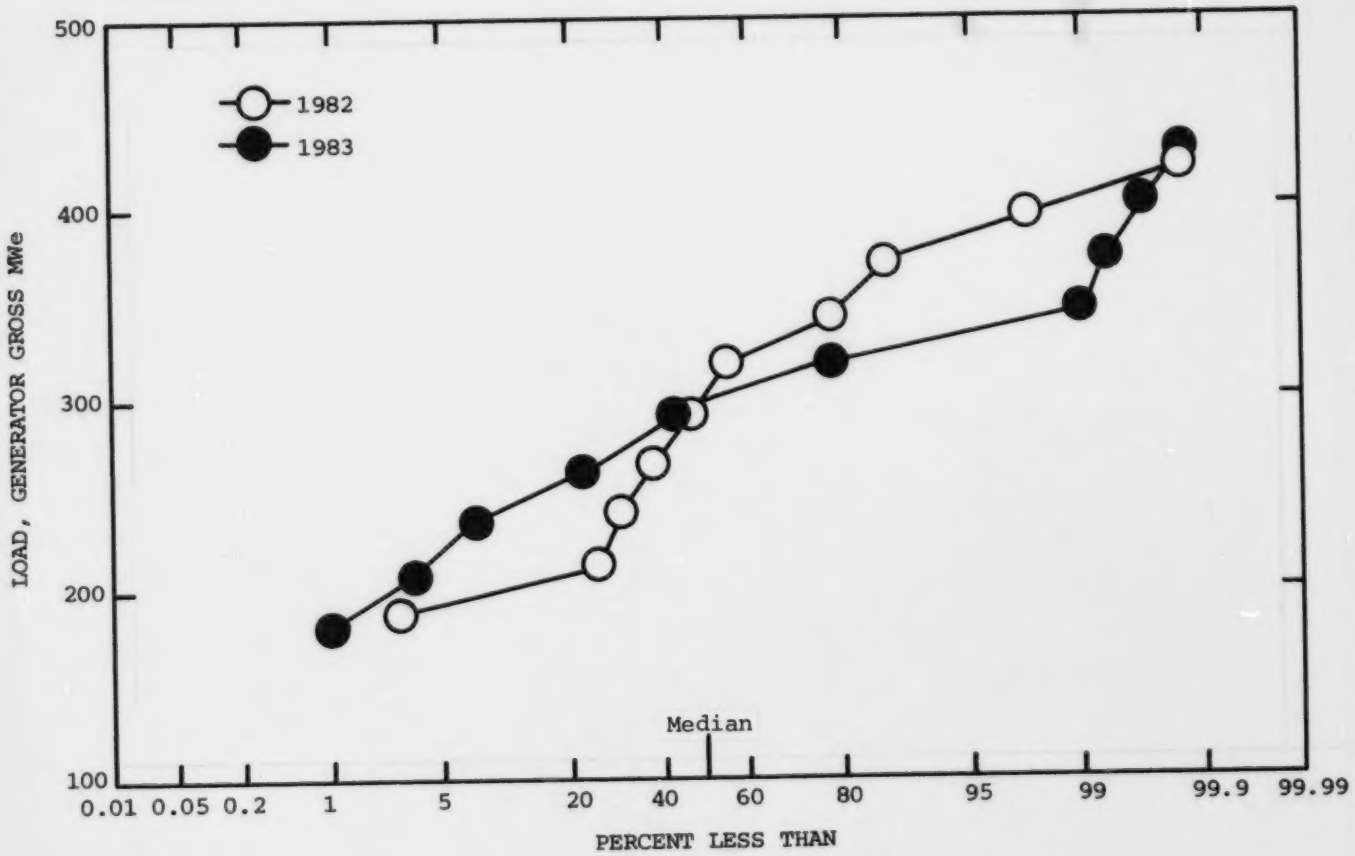


Figure 6-7. Comparison of Load Probabilities - Utah P&L, Hunter Station Unit 2

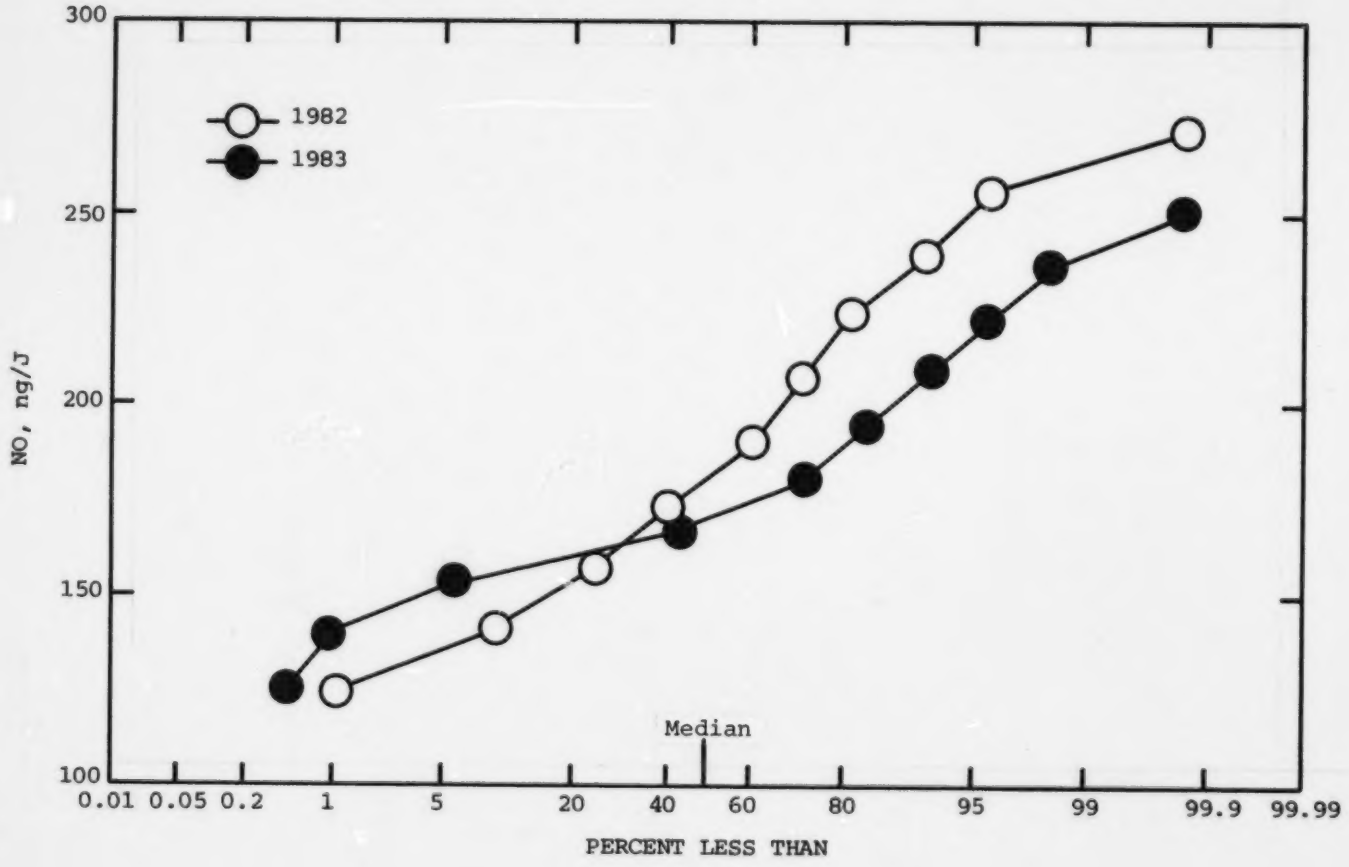


Figure 6-8. Comparison of NO Probabilities - Utah P&L, Hunter Station Unit 2

TABLE 6-1. PRE-MODIFICATION OPERATING PARAMETERS - FULL-LOAD OPERATION

Parameter	Typical Operating Set Point	Short-Term Characterization Test Range
1. Stack Oxygen	4.5%	2.4% to 5.8%
2. Burner Tilt (± degrees from horizontal)	0°	+18° to (-20°)
3. Fuel Air Dampers (percent open)*	100%	100% to 50%
4. Auxiliary Air Dampers (percent open)	20%	0% to 40%
5. Bottom Auxiliary Damper (percent open)	50%	0% to 100%
6. Overfire Air Dampers (percent open)	0%	0% to 100%
7. Overfire Air Tilt (± degrees from horizontal)	Not Applicable	+30° to (-10°)

*Fuel compartment (secondary) air

TABLE 6-2. INSTRUMENT SPECIFICATIONS AND PERFORMANCE
October 1982

Parameter		EPA Performance Specifications	Test Result
A. Thermo Electron Series 10 NO_x Analyzer			
1. Accuracy		≤ 20% of mean ref. value	4.1% (4.5, 3.7)
2. Calibration error	mid	≤ 5% of cal gas value	0.27%
	high	≤ 5% of cal gas value	0.38%
3. Zero drift (2 hour)		≤ 2% of span	0.0014%
4. Zero drift (24 hour)		≤ 2% of span	0%
5. Calibration drift (2 hour)		≤ 2% of span	0.25%
6. Calibration drift (24 hour)		≤ 2.5% of span	0.34%
7. Response time		15 minute maximum	55 sec
8. Operational period		168 hour minimum	720 hr
B. Horiba Instruments PIR 2000 CO_2 Analyzer			
1. Zero drift (2 hour)		≤ 0.4 pct CO_2	0%
2. Zero drift (24 hour)		≤ 0.5 pct CO_2	0%
3. Calibration drift (2 hour)		≤ 0.4 pct CO_2	0.021%
4. Calibration drift (24 hour)		≤ 0.5 pct CO_2	0.14%
5. Response time		10 minutes maximum	61 sec
6. Operational period		168 hour minimum	720 hr
C. Thermox Model III O_2 Analyzer			
1. Zero drift (2 hour)		≤ 0.4 pct O_2	0%
2. Zero drift (24 hour)		≤ 0.5 pct O_2	0%
3. Calibration drift (2 hour)		≤ 0.4 pct O_2	0%
4. Calibration drift (24 hour)		≤ 0.5 pct O_2	0%
5. Response time		10 minutes maximum	70 sec
6. Operational period		168 hour minimum	720 hr
D. Horiba Instruments PIR 2000 CO Analyzer			
1. Calibration error	mid	≤ 5% of cal gas value	1.31%
	high	≤ 5% of cal gas value	1.61%
2. Zero drift (2 hour)		≤ 2% of span	0%
3. Zero drift (24 hour)		≤ 2% of span	0%
4. Calibration drift (2 hour)		≤ 2% of span	0.099%
5. Calibration drift (24 hour)		≤ 2.5% of span	0.11%
6. Response time		15 minute maximum	55 sec
7. Operational period		168 hour minimum	720 hr

TABLE 6-3. INSTRUMENT SPECIFICATIONS AND PERFORMANCE
April 1983

Parameter		EPA Performance Specifications	Test Result
A. Thermo Electron Series 10 NO_x Analyzer			
1. Accuracy		≤ 20% of mean ref. value	$\overline{6.0\%}$ (5.6, 6.4)
2. Calibration error	mid	≤ 5% of cal gas value	0.4%
	high	≤ 5% of cal gas value	0.64%
3. Zero drift (2 hour)		≤ 2% of span	0%
4. Zero drift (24 hour)		≤ 2% of span	0%
5. Calibration drift (2 hour)		≤ 2% of span	0.097%
6. Calibration drift (24 hour)		≤ 2.5% of span	0.27%
7. Response time		15 minute maximum	53 sec
8. Operational period		168 hour minimum	720 hr
B. Horiba Instruments PIR 2000 CO_2 Analyzer			
1. Zero drift (2 hour)		≤ 0.4 pct CO_2	0%
2. Zero drift (24 hour)		≤ 0.5 pct CO_2	0%
3. Calibration drift (2 hour)		≤ 0.4 pct CO_2	0.049%
4. Calibration drift (24 hour)		≤ 0.5 pct CO_2	0.049%
5. Response time		10 minutes maximum	60 sec
6. Operational period		168 hour minimum	720 hr
C. Thermox Model III O_2 Analyzer			
1. Zero drift (2 hour)		≤ 0.4 pct O_2	0%
2. Zero drift (24 hour)		≤ 0.5 pct O_2	0%
3. Calibration drift (2 hour)		≤ 0.4 pct O_2	0%
4. Calibration drift (24 hour)		≤ 0.5 pct O_2	0%
5. Response time		10 minutes maximum	75 sec
6. Operational period		168 hour minimum	720 hr
D. Horiba Instruments PIR 2000 CO Analyzer			
1. Calibration error	mid	≤ 5% of cal gas value	0.5%
	high	≤ 5% of cal gas value	2.89%
2. Zero drift (2 hour)		≤ 2% of span	0%
3. Zero drift (24 hour)		≤ 2% of span	0%
4. Calibration drift (2 hour)		≤ 2% of span	0.155%
5. Calibration drift (24 hour)		≤ 2.5% of span	0.42%
6. Response time		15 minute maximum	60 sec
7. Operational period		168 hour minimum	720 hr

TABLE 6-4. (CONTINUED)

Data Sampled: 4/16/83

PROXIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	5.96	xxxxx
% Ash	14.36	15.27
% Volatile	37.59	39.97
% Fixed Carbon	42.09	44.76
	100.00	100.00
Btu/lb.	11500	12229
% Sulfur	0.55	0.59

ULTIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	5.96	xxxxx
% Carbon	64.44	68.52
% Hydrogen	4.70	5.00
% Nitrogen	1.30	1.38
% Chlorine	0.01	0.01
% Sulfur	0.55	0.59
% Ash	14.36	15.27
% Oxygen(diff)	8.68	9.23
	100.00	100.00

Data Sampled: 4/22/83

PROXIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	17.49	xxxxx
% Ash	15.19	18.41
% Volatile	32.73	39.67
% Fixed Carbon	34.59	41.92
	100.00	100.00
Btu/lb.	9660	11708
% Sulfur	0.50	0.60

ULTIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	17.49	xxxxx
% Carbon	53.78	65.18
% Hydrogen	3.97	4.81
% Nitrogen	1.16	1.41
% Chlorine	0.02	0.02
% Sulfur	0.50	0.60
% Ash	15.19	18.41
% Oxygen(diff)	7.89	9.57
	100.00	100.00

Data Sampled: 4/27/83

PROXIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	8.25	xxxxx
% Ash	13.95	15.20
% Volatile	37.06	40.39
% Fixed Carbon	40.74	44.41
	100.00	100.00
Btu/lb.	11189	12195
% Sulfur	0.49	0.53

ULTIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	8.25	xxxxx
% Carbon	63.14	68.82
% Hydrogen	4.78	5.21
% Nitrogen	1.27	1.36
% Chlorine	0.02	0.02
% Sulfur	0.49	0.53
% Ash	13.95	15.20
% Oxygen(diff)	8.13	8.86
	100.00	100.00

TABLE 6-4. (CONTINUED)

Data Sampled: 5/6/83

PROXIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	6.69	xxxxx
% Ash	13.13	14.07
% Volatile	37.95	40.67
% Fixed Carbon	42.23	45.26
	100.00	100.00
Btu/lb.	11560	12389
% Sulfur	0.51	0.55

ULTIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	6.69	xxxxx
% Carbon	64.92	69.57
% Hydrogen	4.98	5.34
% Nitrogen	1.33	1.42
% Chlorine	0.03	0.03
% Sulfur	0.51	0.55
% Ash	13.13	14.07
% Oxygen(diff)	8.41	9.02
	100.00	100.00

Data Sampled: 5/13/83

PROXIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	6.72	xxxxx
% Ash	11.37	12.19
% Volatile	38.08	40.82
% Fixed Carbon	43.83	46.99
	100.00	100.00
Btu/lb.	11845	12698
% Sulfur	0.46	0.49

ULTIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	6.72	xxxxx
% Carbon	65.15	69.84
% Hydrogen	4.95	5.31
% Nitrogen	1.32	1.42
% Chlorine	0.02	0.02
% Sulfur	0.46	0.49
% Ash	11.37	12.19
% Oxygen(diff)	10.01	10.73
	100.00	100.00

TABLE 6-4.(CONTINUED)

PROXIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	7.15	xxxxx
% Ash	15.41	16.60
% Volatile	36.73	39.56
% Fixed Carbon	40.71	43.84
	100.00	100.00
Btu/lb.	11110	11966
% Sulfur	0.48	0.52

ULTIMATE ANALYSIS	As Rec'd	Dry Basis
% Moisture	7.15	xxxxx
% Carbon	62.11	66.89
% Hydrogen	4.61	4.96
% Nitrogen	1.35	1.45
% Chlorine	0.00	0.00
% Sulfur	0.48	0.52
% Ash	15.41	16.60
% Oxygen(diff)	8.89	9.58
	100.00	100.00

Composite of samples taken:

4/11/83
4/24/83
5/2/83
5/11/83

TABLE 6-5. PRE-MODIFICATION COAL PROXIMATE ANALYSIS RESULTS

Utah P&L, Hunter Station Unit 2

August 1981

No. of Samples	58
Mean Moisture, %	7.56
Moisture Standard Deviation, %	0.87
Mean Ash, %	13.59
Ash Standard Deviation, %	1.97
Mean Volatile Matter, %	39.13
Volatile Standard Deviation, %	1.15
Mean Fixed Carbon, %	39.72
Carbon Standard Deviation, %	1.40
Mean Heating Value, Btu/lb (kJ/kg)	11,352 (26,405)
Heating Value Standard Deviation, Btu/lb (kJ/kg)	350 (814)
Mean Sulfur, %	0.538
Sulfur Standard Deviation, %	0.048

TABLE 6-6.

PRE-MODIFICATION COAL ANALYSES OBTAINED BY COMBUSTION ENGINEERING

Utah P&L, Hunter Station Unit 2

1981 Date Sampled	Proximate Analysis	As Rec'd	Dry Basis	Ultimate Analysis	As Rec'd	Dry Basis
August 10						
	% Moisture	9.0	xxxxx	% Moisture	9.0	xxxxx
	% Ash	13.7	15.1	% Carbon	62.1	68.2
	% Volatile	37.0	40.6	% Hydrogen	4.7	5.2
	% Fixed Carbon	40.3	44.3	% Nitrogen	1.2	1.3
				% Sulfur	0.7	0.8
	Btu/lb.	11,025		% Ash	13.7	15.1
	kJ/kg	25,644		% Oxygen (diff)	8.6	9.4
August 14						
	% Moisture	9.3	xxxxx	% Moisture	9.3	xxxxx
	% Ash	16.9	18.6	% Carbon	58.5	64.4
	% Volatile	36.0	39.7	% Hydrogen	4.6	5.0
	% Fixed Carbon	37.8	41.7	% Nitrogen	1.1	1.2
				% Sulfur	0.7	0.8
	Btu/lb.	10,470		% Ash	16.9	18.6
	kJ/kgr	24,353		% Oxygen (diff)	8.9	10.0

TABLE 6-7. POST-MODIFICATION MEDIAN AND MEAN VALUES
Utah P&L, Hunter Station Unit 2

	1982	1983
Median Load, Gross MWe	305	296
Median Load, % of Rating	71.8	69.7
Mean Load, Gross MWe	288	287
Mean Load, % of Rating	67.8	67.5
Median NO, ng/J	182	170
Mean NO, ng/J	186	175
Median O_2, %, dry*	--	--
Mean O_2, %, dry	5.79	3.77

*The data reduction computer program did not have the capability to determine the O_2 probability for these cases.

SECTION 7.0

UNITS B AND C

7.1 INTRODUCTION

The steam output of these boilers is used to supply a single steam turbine. The generator is rated at 720 gross MWe. Each boiler is capable of completely independent operation and each is equipped with a dedicated in-situ continuous emission monitor (CEM). Both boilers exhaust through one stack and for regulatory purposes they are considered to be a single source. The CEM outputs are also combined to produce a single value of NO (and O_2) in order to demonstrate compliance with the 1971 New Source Performance Standard.

Each boiler is opposed-face-fired and was originally equipped with a total of 24 single-register Flare burners arranged in three elevations of four burners/elevation. Overfire air ports (OFAP) and underfire air ports (UFAP) were included in the original design. The coal fired is classified as a high-volatile "A" bituminous.

7.2 PERFORMANCE TESTS

During December 1980, the boiler manufacturer performed short-duration gaseous emission measurements on both units using a chemiluminescent analyzer (for NO) and an Orsat analysis (for O_2). The results, at a combined generator load of 675 gross MWe (93.8 percent of rating) were:

Unit B; 1.09 lb $NO_x/10^6$Btu - 460 ng/J
Unit C; 0.96 lb $NO_x/10^6$Btu - 413 ng/J

These results were in excess of the 1971 NSPS, and were used to demonstrate the high NO_x levels to the boiler manufacturer. During these measurements, the OFAP and UFAP were 1/3 open and fully closed, respectively.

The official performance tests, as required by the 1971 NSPS, was conducted on January 8, 1982, at a combined generator output of 690 gross MWe (95.8 percent of rating). These results were:

Unit B; 0.40 lb $NO_x/10^6$Btu - 172 ng/J
Unit C; 0.42 lb $NO_x/10^6$Btu - 181 ng/J

The OFAP and UFAP were fully open for these short-duration tests. Full-scale tests performed by the boiler manufacturer (Reference 5-2) have shown that opening the UFAP reduces NO_x by approximately 12 percent. Therefore, a portion of the lower NO_x measured during the official performance tests was attributed to the fully open UFAP.

7.3 BOILER MODIFICATIONS

During the time period between September 1981 and June 1982, the burners in both boilers were replaced for the express purpose of reducing NO_x emissions. This replacement consisted of substituting the single-register Controlled Combustion Venturi (CCV) burner for the single-register Flare burner. (See Section 5-4 for a discussion of both burners.) In addition, a larger superheater and flue gas recirculation (above the OFAP) were retrofitted to raise the steam temperature from about 900°F (756 K) to its design level of 1005°F (814 K).

The CCV burners and the larger superheater were in-place prior to the January 8, 1982 official performance tests. The flue gas recirculation systems, for additional steam temperature control, was added after the performance tests. The utility assessed that the FGR systems, located above the OFAP, would not have any significant effect on NO_x emissions.

7.4 CONTINUOUS EMISSION MONITOR

Each unit is equipped with a dedicated in-situ CEM which is located in the stack breeching. Tables 7-1 and 7-2 summarize the results of the NO and O_2 monitor performance tests as well as the EPA specifications. As noted, the monitor certification occurred after the boiler modifications, therefore, CEM data was not available for the time period prior to the modifications.

7.5 DATA PACKAGES

The utility supplied data packages consisting of:

1. CEM hourly averaged values of NO and O_2 for the time periods of June 19, 1983 - July 16, 1983, and July 31, 1983 - August 6, 1983.

2. Hourly averaged generator output in gross MWe for the same time periods.

3. Weekly composite coal analyses of heating value and sulfur content. The coal samples were taken on a daily basis from the conveyor leading to the bunkers.

The coal properties are presented in Table 7-3. These properties were not sufficient to establish the degree of coal constancy during the above time periods.

7.6 DATA ANALYSIS

The hourly averaged data (711 hours for Unit B and 641 hours for Unit C) were analyzed by an extended version of the computer program described in Reference 2-1. The key results are shown in Figure 7-1 which compares the mean values of NO and O_2 vs. load for Units B and C. (The data shown for Unit C was prepared by sorting it over the Unit B load range. This would facilitate the subsequent statistical analysis.)

Of note from Figure 7-1 are the similar trends in NO and O_2 vs. load for both units, and the degree to which the NO at high-load exceeds the performance test conducted on January 8, 1982. (The broken lines shown in Figure 7-1 for Unit B are due to the few number of data at the lowest load.) The reasons for this exceedance are:

1. The overfire air ports are automatically controlled to open when the NO approaches an alarm level of 370 ppm. This level corresponds to approximately 0.68 lb/10^6Btu (292 ng/J). The overfire air ports were fully open during the performance test.

2. The operation of the units is not expressly for the purpose of minimizing NO emissions.

The above results illustrate that although these units have a short-term capability to achieve NO_x levels of 0.40-0.42 lb/10^6 Btu (172-181 ng/J), normal long-term, day-to-day operation is at NO levels of 0.57-0.65 lb/10^6 Btu (244-279 ng/J). The long-term CEM data for both units were compared to the 1971 NSPS on 3-hour rolling and block average bases. It was determined that Unit B was in excess of the NO_x limit (0.7 lb/10^6 Btu, 300 ng/J) for 8.3 and 10.1 percent for the rolling and block average basis, respectively. By comparison, Unit C was in excess of the NO_x limit for only 0.63 and 0.94 percent for the rolling and block average basis, respectively.

An analysis was performed of the mean NO for Units B and C within each of the ten load cells to determine if the means were statistically different. The results of this analysis are presented in Figure 7-2 and indicate that, at most, there was a 14.3 percent difference at the 95 percent confidence level. There was no statistical difference for five of the ten load cells. The utility assessed that a difference as large as 14.3 percent for nominally identical boilers is not of practical significance.

Figures 7-3 and 7-4 are comparisons of load and NO on a diurnal basis. As noted in Figure 7-3, both units "track" each other but with Unit B running at a slightly higher load. The difference in the diurnal NO, therefore, was due to the difference in NO vs. load characteristic (cf. Figures 7-1 and 7-2).

Figures 7-5 and 7-6 compare the load and NO distributions, respectively, with the NO being nearly normally distributed.

Table 7-4 summarizes the mean and median values of load, NO and O_2 for each unit as developed from the data. It was assessed that based on the NO probability distributions (Figure 7-6), Unit B's emissions would have been equal to or less than the 1978 NSPS for 66.0 percent of the time, while for Unit C this value would be 90.3 percent.

7.7 OPERATIONAL IMPACTS

A discussion was held with the plant operating supervisor to determine if the burner substitution had produced any significant impacts on boiler

operation. It was determined that there has been a large increase in the flyash unburned carbon content. Whereas the unburned carbon was 1.5-2 percent with the Flare burner, the flyash carbon with the CCV burner is on the order of 8-10 percent with a peak value as high as 22 percent. Previously, the flyash had been sold to cement manufacturers, however, the high carbon content with the CCV burners makes the flyash unacceptable for this purpose. The plant is contemplating replacing the CCV burners in the lowest level with the Flare burner in order to reduce the unburned carbon, at the expense of increasing the NO_x.

The flame standoff distance (at full load) has also been affected by the burner substitution. For the Flare burner this distance was on the order of 10-12" (25-30 cm), while on occasion the standoff distance has been 2-4 ft. (0.6-1.2 m) for the CCV burner. However, there has been no indication that the CCV burner has caused any flame impingement on the opposite wall in these opposed-wall-fired boilers. The boilers have not experienced any slagging problems with either burner type. The plant personnel have also indicated that the Flare burner spreads the coal to a greater extent than the CCV burner. As a result, the initial flame shape occupies a greater included angle. This is in agreement with the observations reported in Reference 5-1.

7.8 CONCLUSIONS

Based on CEM data and performance test results for Units B and C it was concluded that:

1. Normal day-to-day operation of these units (with UFAP open and OFAP open only at alarm level) achieves NO in the range of 0.57-0.65 lb/10^6 Btu (244-279 ng/J). These levels represent NO reductions of 40 percent with respect to the original tests conducted by the boiler manufacturer.

2. There are statistically significant differences in NO at certain load ranges for these nominally identical units. However, these differences are probably not significant on a practical operational basis.

3. The burner substitution had produced a significant increase in flyash unburned carbon content.

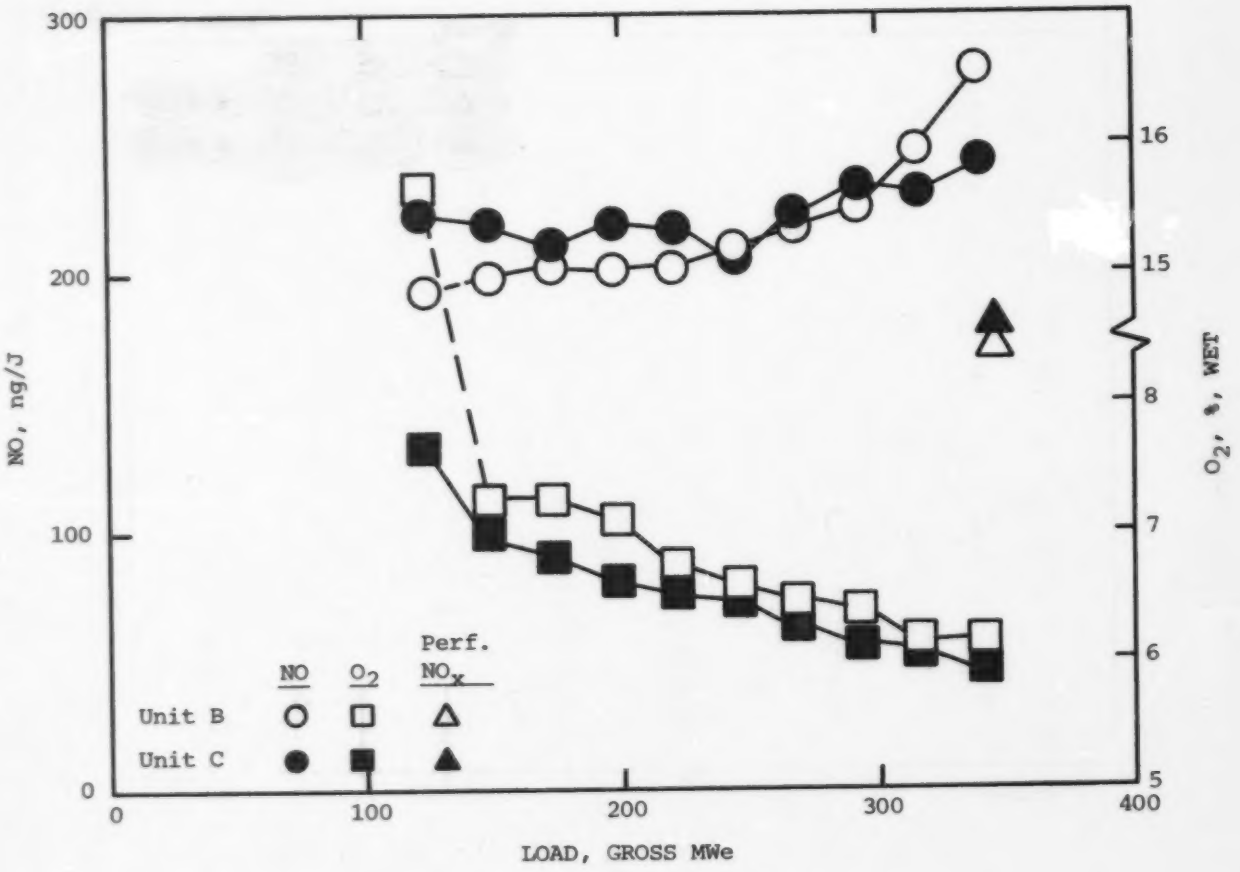


Figure 7-1. Boiler NO and O_2 Characteristics - Units B and C

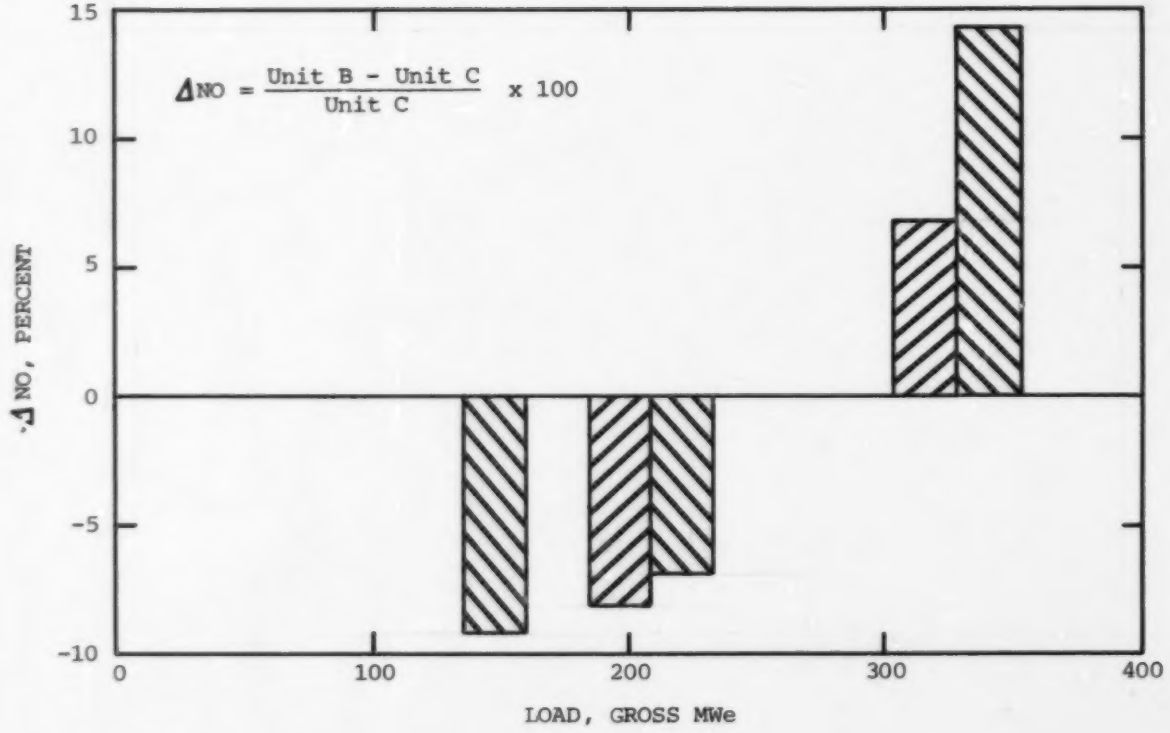


Figure 7-2. Difference in NO between Units B and C

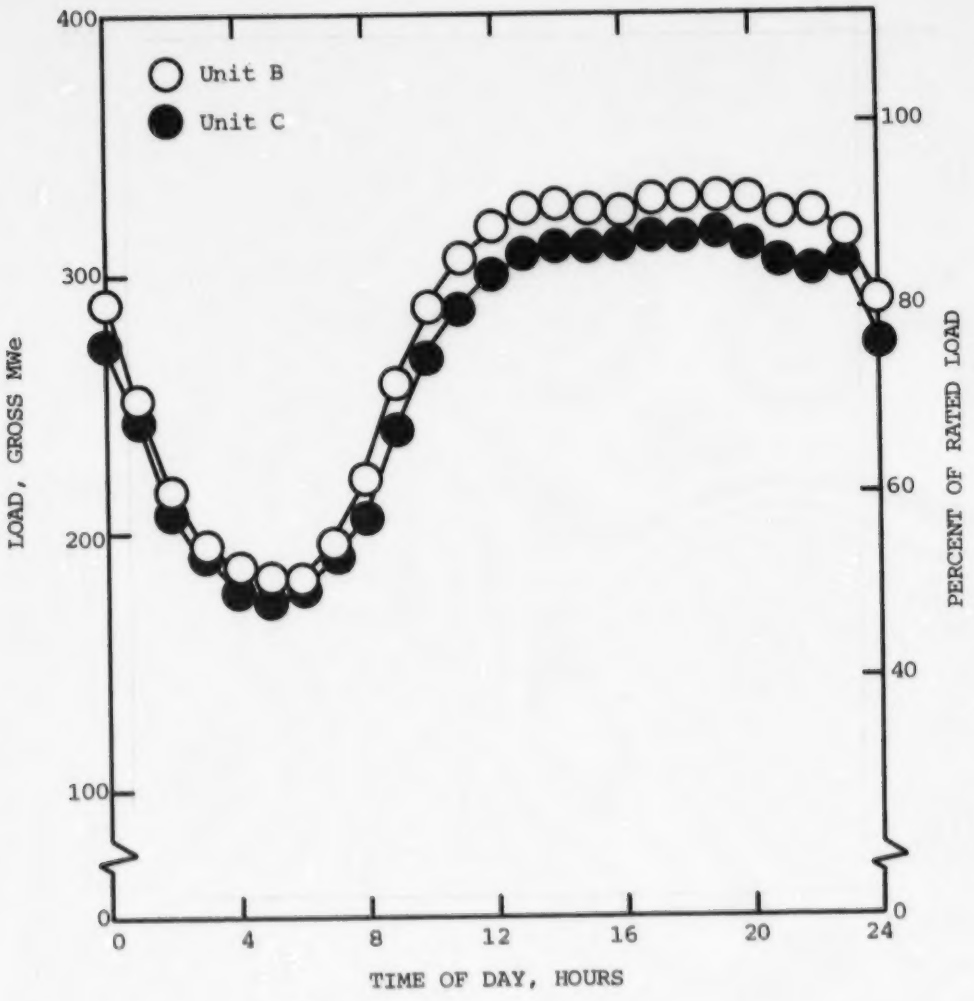


Figure 7-3. Load Comparison on a Diurnal Basis - Units B and C

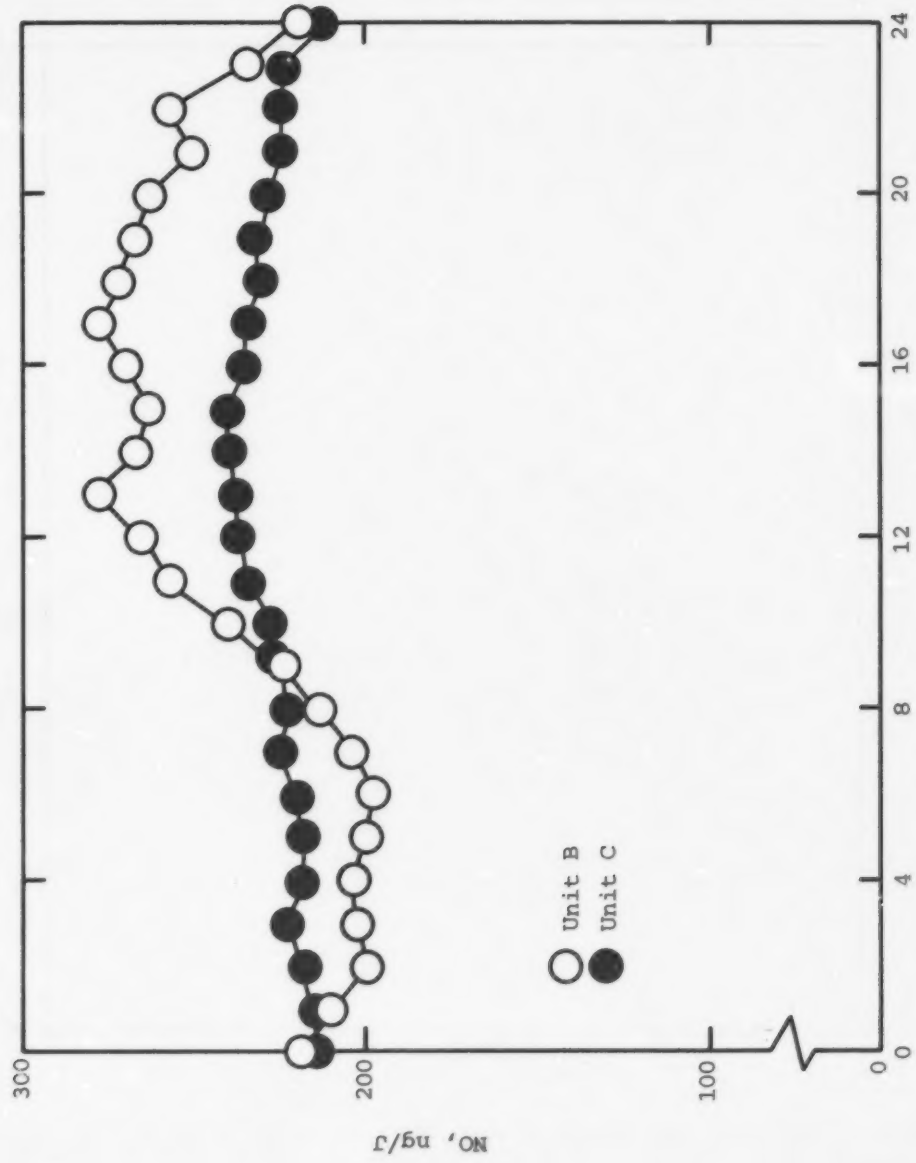


Figure 7-4. NO Comparison on a Diurnal Basis - Units B and C

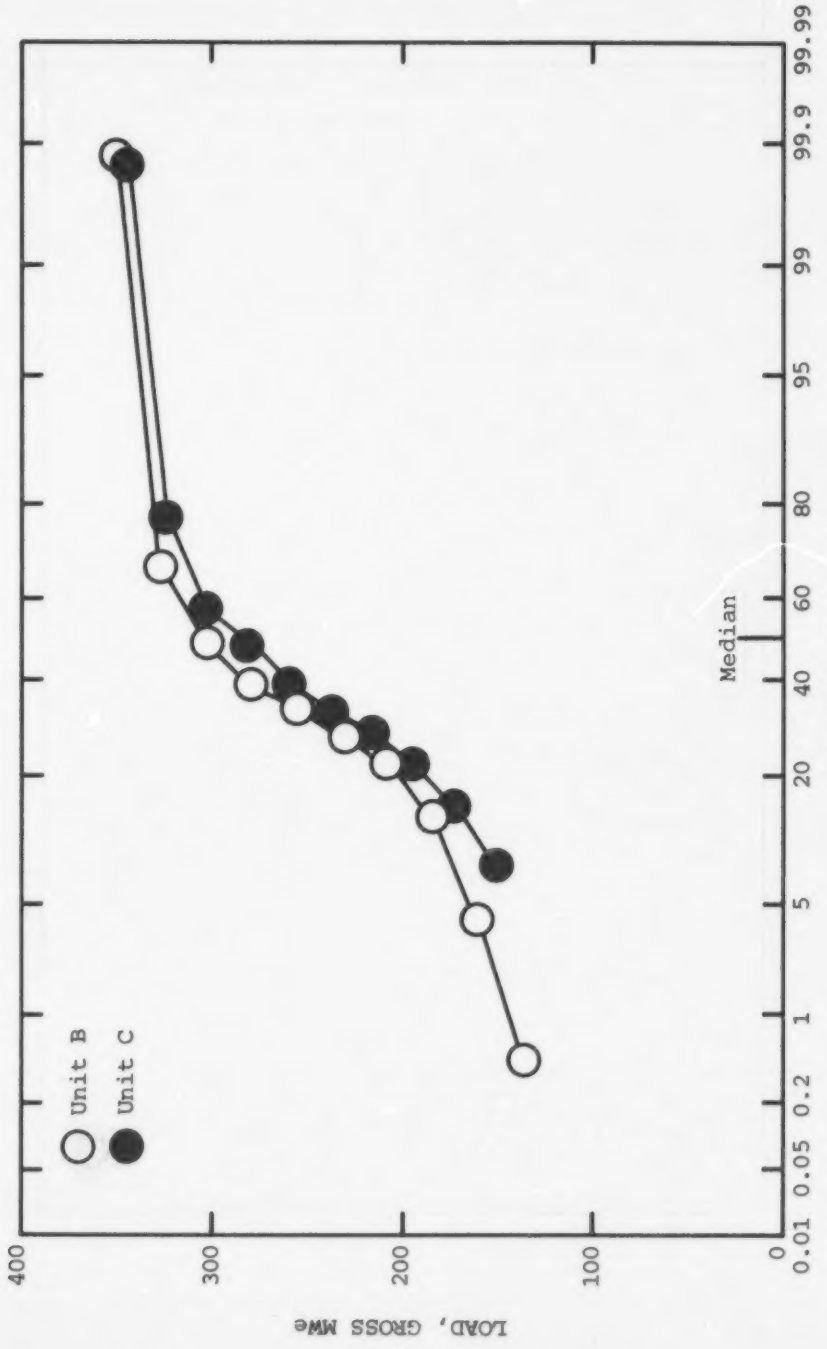


Figure 7-5. Load Distribution Comparison - Units B and C

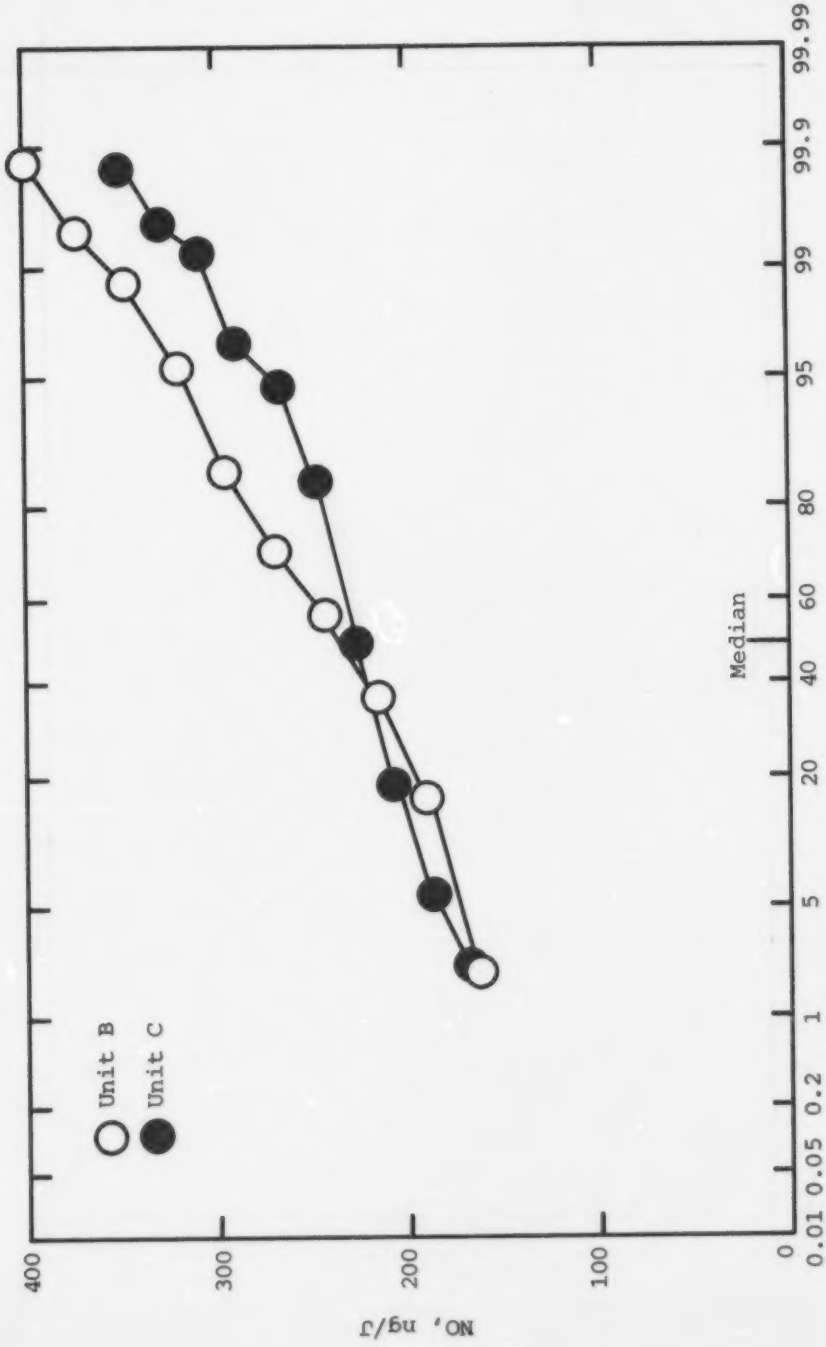


Figure 7-6. NO Distribution Comparison - Units B and C

TABLE 7-1. SUMMARY OF RESULTS FOR UNIT B CEM

January 21-28, 1983

Parameter	EPA Specification	Test Result
LSI SM810 NO Monitor		
Relative Accuracy	< 20%	10.4%
Response Time	< 15 min	167 sec
Calibration Error		
High	< 5%	1.6%
Med	< 5%	2.2%
2-Hour Zero Drift	< 2%	0.2%
2-Hour Calibration Drift	< 2%	0.4%
24-Hour Zero Drift	< 2%	0.5%
24-Hour Calibration Drift	< 2.5%	0.8%
Operational Test Period	> 168 hrs	168 hrs
LSI CM50 O_2 Monitor		
Response Time	< 10 min	9 sec
2-Hour Zero Drift	< 0.4%	0.2%
2-Hour Calibration Drift	< 0.4%	0.3%
24-Hour Zero Drift	< 0.5%	0.0%
24-Hour Calibration Drift	< 0.5%	0.5%
Operational Test Period	> 168 hrs	168 hrs

TABLE 7-2. SUMMARY OF RESULTS FOR UNIT C CEM

January 20-27, 1983

Parameter	EPA Specification	Test Result
LSI SM810 NO Monitor		
Relative Accuracy	< 20%	13.1%
Response Time	< 15 min	123 sec
Calibration Error		
High	< 5%	1.3%
Med	< 5%	0.8%
2-Hour Zero Drift	< 2%	0.1%
2-Hour Calibration Drift	< 2%	0.2%
24-Hour Zero Drift	< 2%	0.3%
24-Hour Calibration Drift	< 2.5%	0.6%
Operational Test Period	> 168 hrs	168 hrs
LSI CM50 O_2 Monitor		
Response Time	< 10 min	12 sec
2-Hour Zero Drift	< 0.4%	0.2%
2-Hour Calibration Drift	< 0.4%	0.2%
24-Hour Zero Drift	< 0.5%	0.0%
24-Hour Calibration Drift	< 0.5%	0.48%
Operational Test Period	> 168 hrs	168 hrs

TABLE 7-3.

COMPOSITE WEEKLY COAL ANALYSES FOR UNITS B AND C

1983

Week	Heating Value Btu/lb	Heating Value kJ/kg	Sulfur % By Weight
5/28 - 6/03	11,481	26,705	0.6
6/04 - 6/10	12,416	28,880	0.6
6/11 - 6/17	12,430	28,912	0.7
6/18 - 6/24	12,472	29,010	0.7
6/25 - 7/01	12,309	28,631	0.7
7/02 - 7/08	12,269	28,538	0.7
7/09 - 7/15	12,385	28,808	0.6
7/16 - 7/22	11,690	27,191	0.6
7/23 - 7/29	12,809	29,794	0.7

TABLE 7-4. MEAN AND MEDIAN VALUES - UNITS B AND C

	Unit B	Unit C
Mean load, gross MWe	277	265
% of rating	77.0	73.7
Median load, gross MWe	306	285
% of rating	85.0	79.2
Mean NO, ng/J	239	227
$lb/10^6$ Btu	0.556	0.529
Median NO, ng/J	235	227
$lb/10^6$ Btu	0.547	0.528
Mean O_2, %, wet	6.52	6.33
Median O_2, % wet	~ 6.4	~ 6.3

SECTION 8.0

NEBRASKA PUBLIC POWER DISTRICT, GERALD GENTLEMAN STATION UNIT 1

8.1 INTRODUCTION

This unit was manufactured by Foster Wheeler and has a generator output of 680 gross MWe. It is opposed-face-fired with a total of 32 single register Intervane burners in four elevations (4 x 4 pattern on each face). It is equipped with overfire air ports (OFAP) located above the top burner row. It is fueled with subbituminous coal.

The performance test conducted during September 1979 with the OFAP closed yielded a NO_x result in excess of the 1971 NSPS. The performance test was subsequently repeated during September 1982 with the OFAP open and demonstrated compliance with the 1971 NSPS.

8.2 PERFORMANCE TESTS

During September 10-17, 1979 Gentleman Unit 1 was performance tested simultaneously with the continuous emission monitor (CEM) certification. The resulting average Method 7 NO_x was 1.10 lb/10^6 Btu (473 ng/J). The utility contends that this test was conducted with inaccurately calibrated equipment (Reference 8-1). There is some evidence to support this contention in that the simultaneous Method 7 tests for CEM certification (at least those conducted at high load) had an average value of 0.86 lb/10^6 Btu (370 ng/J). These results were obtained with the OFAP closed.

The unit performance test was repeated on September 3, 1982 with the OFAP 50 percent open. This test was held in conjunction with a re-evaluation of the NO analyzer relative accuracy. It was determined that the unit NO_x performance was 0.354 lb NO_x/10^6 Btu (152 ng/J) with the unit load between 576-628 gross MWe (85-92 percent of rating). Thus, on a short-term basis opening of the overfire air ports achieved a NO_x reduction of either 59 percent (370 ng/J vs. 152 ng/J) or 68 percent (473 ng/J vs. 152 ng/J).

8.3 PERFORMANCE TEST COMPARISON WITH OTHER UNITS

According to the utility (Ref. 8-1), the only modification implemented was the adjustment of the OFAP. Reference 1-1 reported the performance test results obtained on Iowa Public Service, Neal Station Unit 4, another Foster Wheeler boiler equipped with Intervane burners and an overfire air system (630 gross MWe, opposed-face-fired). This unit achieved a performance NO_x of 0.345 $lb/10^6$ Btu (148 ng/J) after the overfire air flow had been increased by placing selected burners-out-of-service (BOOS). It was estimated that this mode of operation resulted in a NO_x reduction of 57-62 percent. These levels of performance NO_x and NO_x reduction are comparable to that measured on Gentleman 1. Apparently, a low windbox-to-furnace pressure differential was limiting the amount of overfire air on Neal 4.

Reference 1-1 also reported the effect of overfire air on NO_x for Public Service Company of New Mexico, San Juan Station Unit 1. In this instance, the use of overfire air produced a 40 percent reduction in performance NO_x for this Foster Wheeler boiler equipped with the single register Intervane burner (360 gross MWe, front-face-fired).

8.4 CONTINUOUS EMISSION MONITOR

Gentleman Unit 1 is equipped with an in-situ CEM installed on the stack at an elevation 235 ft. (71.7 m) above the breeching. The Lear Siegler CEM package includes a model SM810 SO_2/NO dual analyzer and a model CM50 O_2 analyzer.

CEM certification (Reference 8-2) was performed during September 10-17, 1979, with the results shown in Tables 8-1 and 8-2 for the NO and O_2 analyzers, respectively. The NO analyzer relative accuracy, on a $lb/10^6$ Btu (ng/J) basis, was 11.3 percent.

On December 11, 1981, a full CEM evaluation was performed by an EPA contractor (Reference 8-3). The NO analyzer relative accuracy was evaluated on both a ppm and $lb/10^6$ Btu (ng/J) basis with the results being 23.5 and 28.1 percent, respectively. (It is to be noted that the NO relative accuracy on a mass basis is a proposed modification of Performance Specification 2.)

On September 3, 1982, the NO analyzer relative accuracy test was repeated by a contractor retained by the utility with the result being 12.9 percent on a ppm basis (Reference 8-4). The unit NO_x performance test was also repeated during this activity.

Table 8-3 summarizes the various results obtained for both the NO analyzer's relative accuracy and the unit's NO_x performance. As noted, the NO relative accuracy was in excess of the EPA specification during the December 11, 1981 test program.

There is evidence to suggest that the unit was in compliance with the NO_x provisions of the 1971 NSPS during the CEM evaluation conducted on December 11, 1981. The mean NO_x calculated from the Method 7 results was 0.36 $lb/10^6$ Btu (155 ng/J), however, this result is assumed to be unofficial. In addition, the mean unit load during the CEM evaluation was only 75 percent of rating.

8.5 DATA PACKAGE

The utility supplied a data package consisting of:

1. CEM and load (gross MWe) data for the time periods of November 20-28, 1979 and February 8-April 30, 1980. The former period corresponds to operation with the OFAP closed while the latter is for operation with the OFAP 50 percent open.

2. Coal proximate analyses for the time period of August 3, 1979 to May 12, 1980.

The utility also indicated that some testing was performed with the OFAP fully open but that there was not a significant additional effect on NO emissions. This might be attributed to a low windbox-to-furnace pressure differential such that there is only a minor increase in overfire air flow beyond a certain damper opening. (A similar situation had been reported in Reference 1-1 for Iowa Public Service, Neal Station Unit 4, another Foster Wheeler unit equipped with the single-register Intervane burner.)

A comparison of the above CEM data dates with those shown in Table 8-3 would indicate that although the CEM had been certified the unit had not yet passed the performance test.

8.6 DATA ANALYSIS

Analyses were performed on the CEM and load data with the OFAP closed* and 50 percent open. Very few data (136 hours) were available for the former while a much larger data base (1705 hours) was supplied for the latter.

Figure 8-1 compares the NO versus load characteristic for both operating configurations. (The broken lines shown in this, and subsequent figures, indicates that only a few data points were available in the corresponding load range.) A comparison of the high load NO results with the performance NO_x values demonstrates that:

1. The CEM values are 22 percent higher than the performance NO_x for the 50 percent open OFAP configuration.

2. No definitive statement can be made for the OFAP closed configuration due to the lack of sufficient CEM data. However, the CEM data that is available appears to agree with the performance NO_x.

In addition, with respect to the OFAP closed condition, the 50 percent OFAP configuration was lower in NO emissions with this difference ranging from 42 to 61 percent across the load range. These differences are on the order of the difference in performance NO_x.

Figure 8-2 is the O_2 versus load characteristic for both operating configurations. An analysis of these data indicated that, except for the highest load range, there was a statistically significant difference in O_2 at the 95 percent confidence level with this difference ranging up to 1.35 percentage points. Differences in O_2 of this order are probably responsible for a portion of the NO vs. load differences referred to above.

Figures 8-3 and 8-4 are the diurnal load and NO comparisons, respectively. The "spikiness" of the data for the OFAP closed configuration was due to the few points (4-7) available. By contrast, the OFAP 50 percent open configuration, with its more extensive data, would indicate that Gentleman

*A minimum amount of air, for cooling purposes, is being passed through the OFAP in the "closed" position.

Unit 1 is being operated in a base loaded manner as evidenced by the near-constant load. As a result of this operation, the diurnal NO shows little variation.

Figures 8-5 and 8-6 are the load and NO probability distribution comparisons, respectively. These distributions, as well as other statistical data, are summarized in Table 8-4.

8.7 COMPARISON WITH 1971 NSPS AND 1978 NSPS

The data reduction computer program calculates the 3-hour average NO on both a rolling and block basis and compares these averages with the appropriate limitation contained in the 1971 NSPS.

In the OFAP closed configuration the unit was found to be in excess of the 1971 NSPS for 32.8 percent (3-hour rolling average) and 37.8 percent (3-hour block average). No periods of excess emission were determined in the 50 percent open OFAP configuration. A portion of this improvement was probably due to the lower O_2 levels implemented along with the opening of the overfire air ports (as shown in Figure 8-2).

Sufficient data was supplied by the utility to calculate 46, 30-day rolling averages for NO with the OFAP 50 percent open. It is to be noted that this averaging period is contained in the 1978 NSPS and that Gentleman Unit 1 is not subject to the 1978 NSPS. Therefore, the results obtained are to be interpreted in this context.

The NO 30-day rolling averages are presented in Figure 8-7 and indicate a small variation (between 179 and 187 ng/J) for the first 22 averages (which are based on the first 51 days of data). Also shown in Figure 8-7 are the corresponding 30-day rolling averages of load which also exhibit a small variation (between 485 and 518 gross MWe).

However, the subsequent behavior of the NO 30-day rolling average was nearly a monotonic decrease with time, which "tracked" the corresponding load decrease. The load decrease was due to a steam turbine blade failure which resulted in the unit being limited to 41 percent of rated generator gross

output. Prior to that date the mean daily load was 492 gross MWe (72.4 percent of rating) with a standard deviation of 101 gross MWe. Subsequently, the mean daily load decreased to 278 gross MWe (40.9 percent of rating) with a standard deviation of 14 gross MWe. The effect of this sudden load change on the NO 30-day rolling average is "smeared-out" by the long averaging period (as noted in Figure 8-7).

8.8 COAL PROPERTIES

The utility supplied 51 as-received coal proximate analyses for the time period of August 3, 1979 to May 12, 1980. These analyses were performed by their coal supplier prior to the train shipment from the mine. Since the date of usage by the boiler could not be related to the train shipment date, it was decided to group all the analyses together rather than explore for temporal differences in coal properties.

Table 8-5 contains the mean, standard deviation and coefficient of variation for the coal moisture, ash, sulfur and heating value for all 51 samples. (The coefficient of variation, C_v, is the standard deviation expressed as a percentage of the mean. As such, its value is independent of the units of measure.) This coal is characterized by its high moisture and low sulfur content, and is classified as a subbituminous "C" according to ASTM D 388-77. Also of note in Table 8-5 are the low C_v's for moisture and heating value.

8.9 CONCLUSIONS

Based on analyses performed with CEM data, NO_x performance test results and discussions with the utility, it was concluded that:

1. Overfire air achieved a short-term NO_x reduction of 59-68 percent. This reduction is consistent with that measured on another Foster Wheeler boiler for which adjustments were made to the overfire air system.

2. Normal day-to-day operation produced a NO level of approximately 200 ng/J (0.47 lb/10^6 Btu) at high load with the overfire air ports 50 percent open. Compared to operation with the overfire air ports closed this level represents a

NO_x reduction of 49-60 percent. Lower O_2 operation, in combination with opening of the OFAP, was probably responsible for the reduced NO levels at lower loads.

3. This unit could comply with the NO_x provisions of the 1978 NSPS for subbituminous coal. This conclusion is based on the 30-day rolling averages obtained prior to the steam turbine blade failure. The lower loads (and NO emissions) subsequent to this failure were considered not to be representative of normal unit operation.

4. Operation with the OFAP fixed in the 50 percent open position has produced no adverse impacts on the unit, i.e., no tendency for increased slagging/fouling/corrosion.

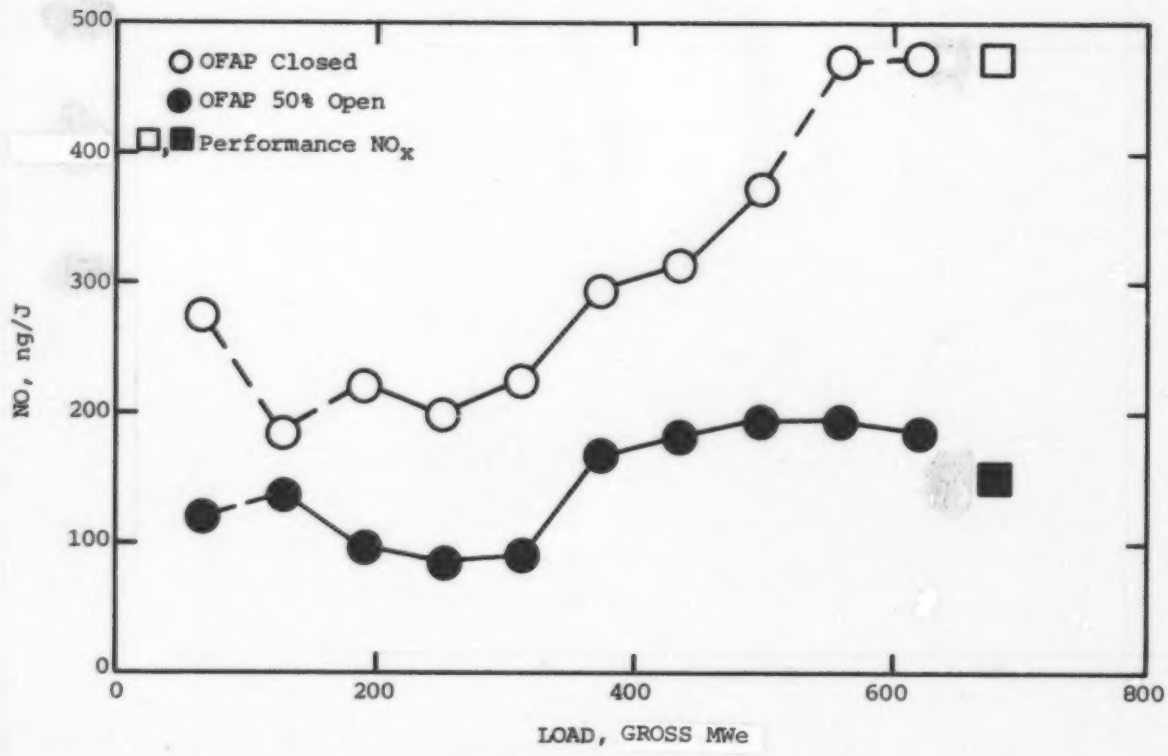


Figure 8-1. NO vs. Load - Gentleman Unit 1

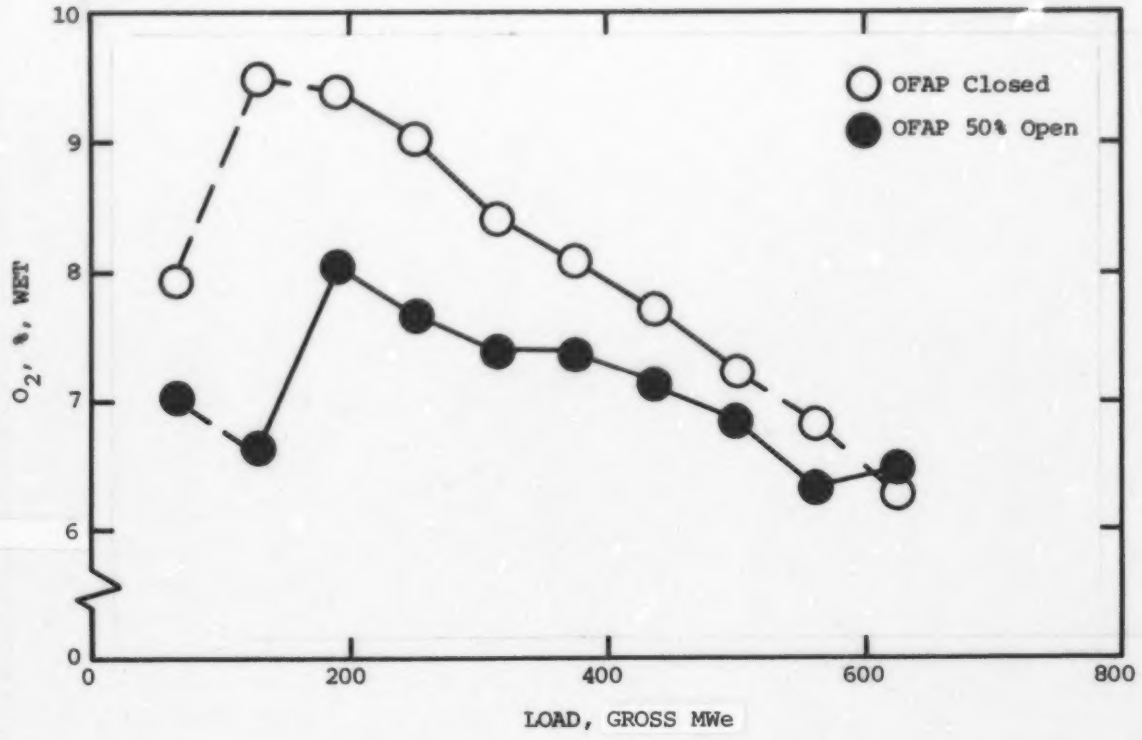


Figure 8-2. O_2 vs. Load - Gentleman Unit 1

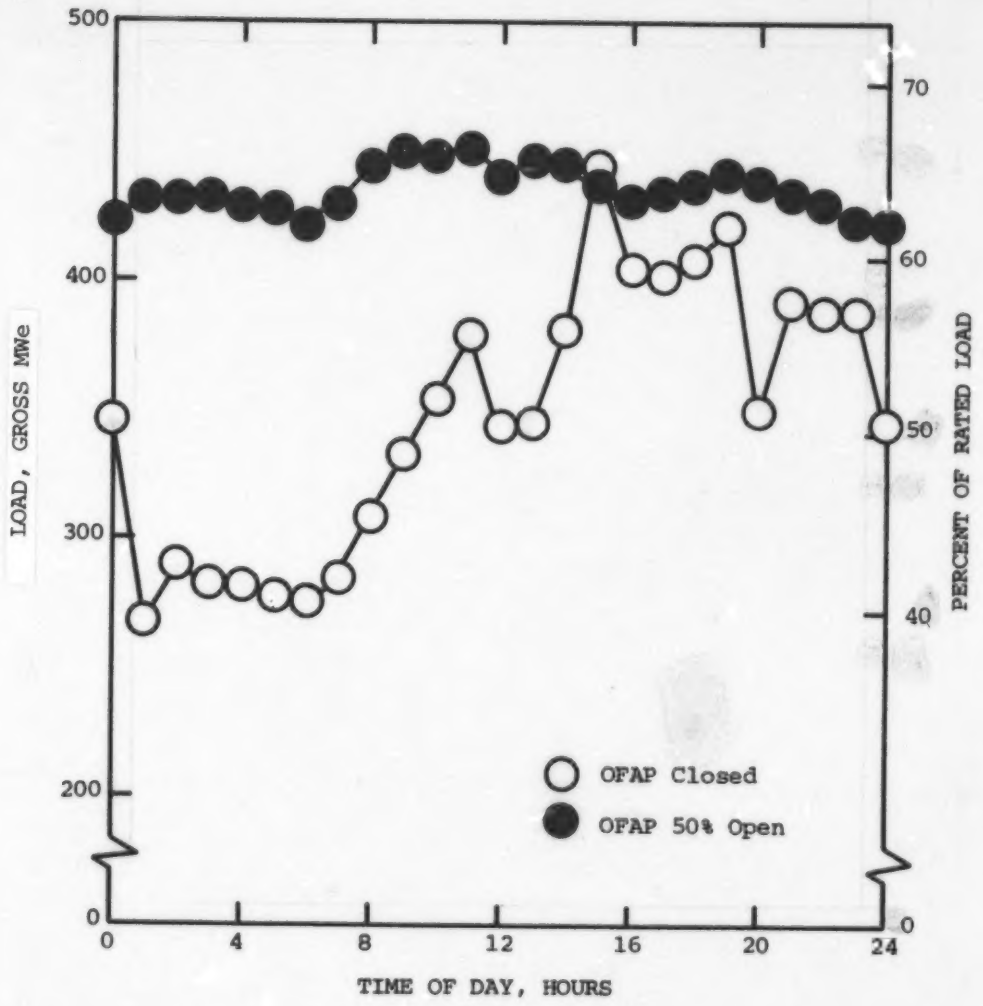


Figure 8-3. Load on a Diurnal Basis - Gentleman Unit 1

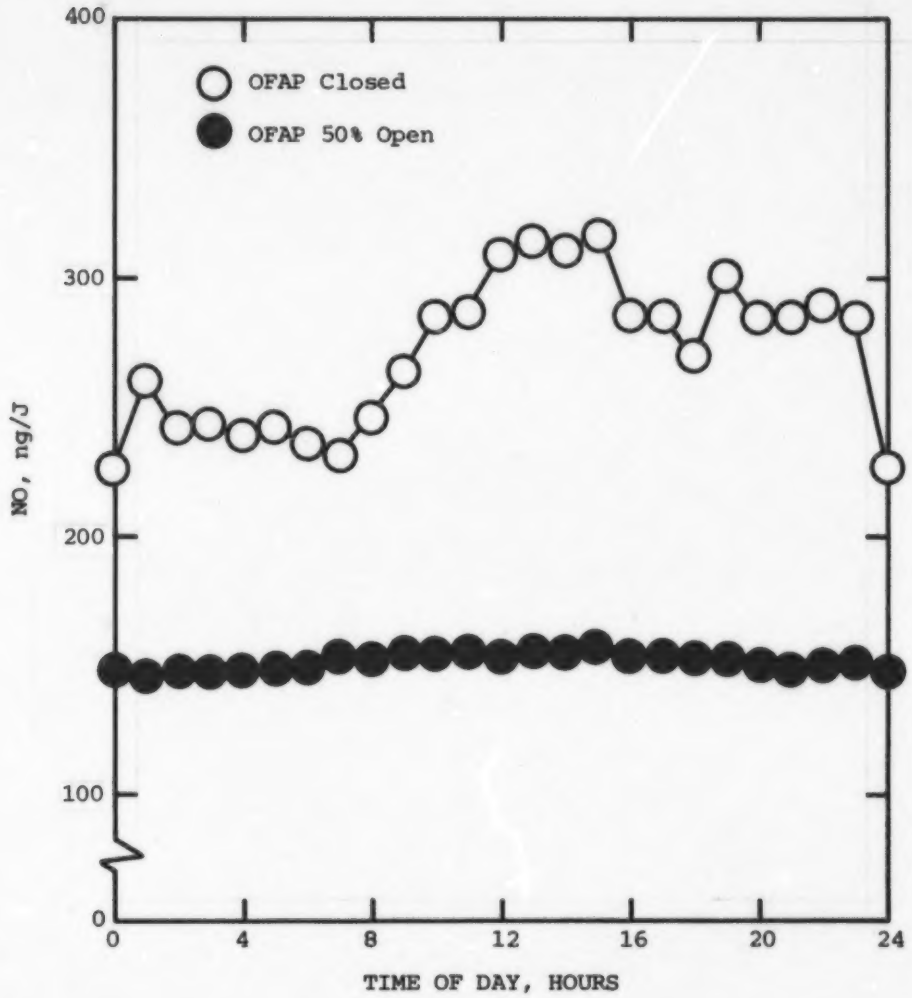


Figure 8-4. NO on a Diurnal Basis - Gentleman Unit 1

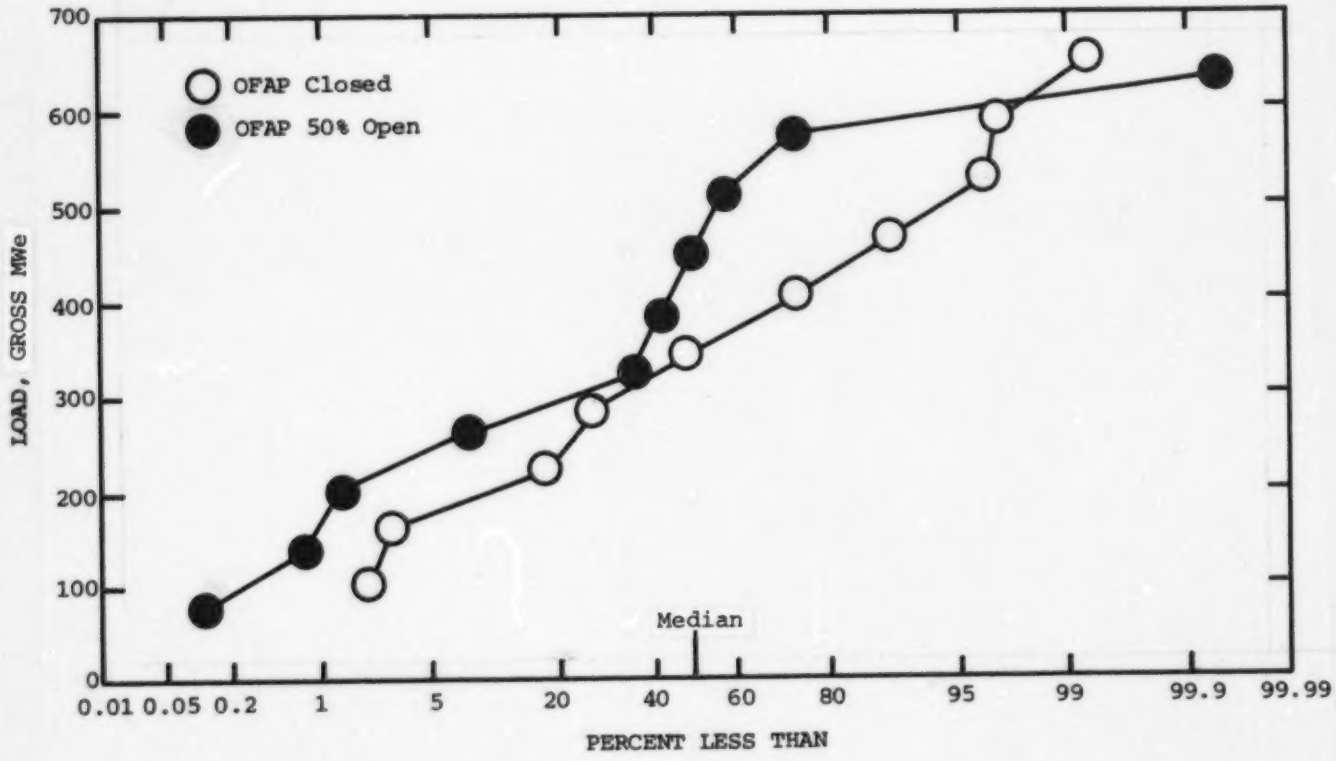


Figure 8-5. Load Distribution - Gentleman Unit 1

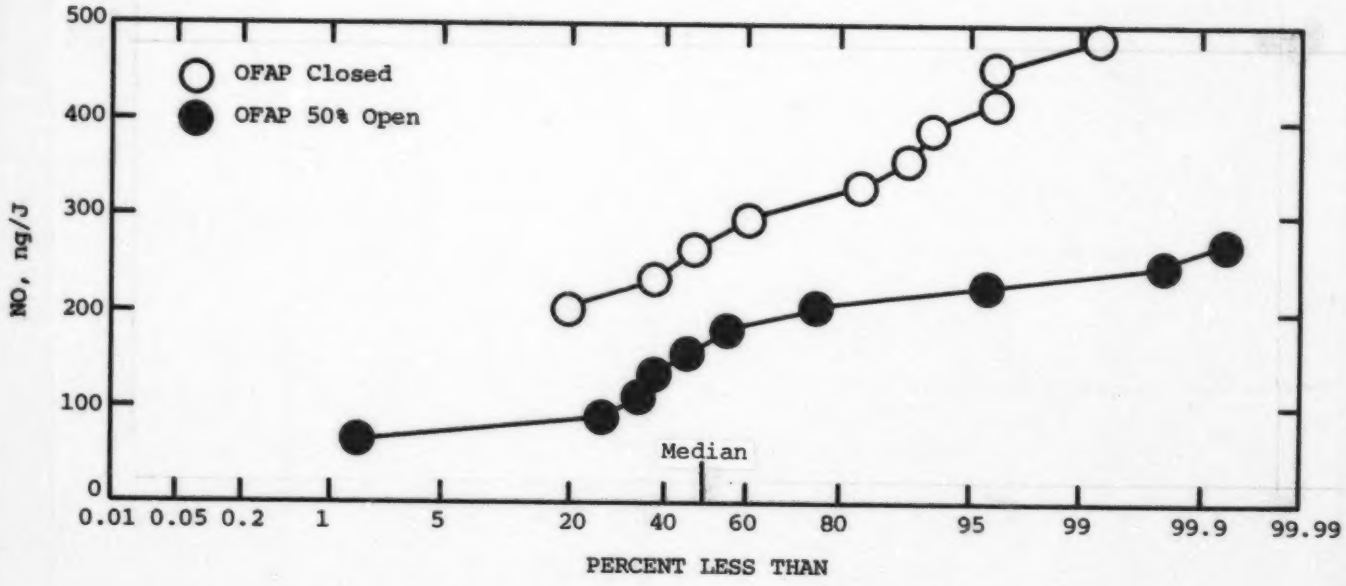


Figure 8-6. NO Distribution - Gentleman Unit 1

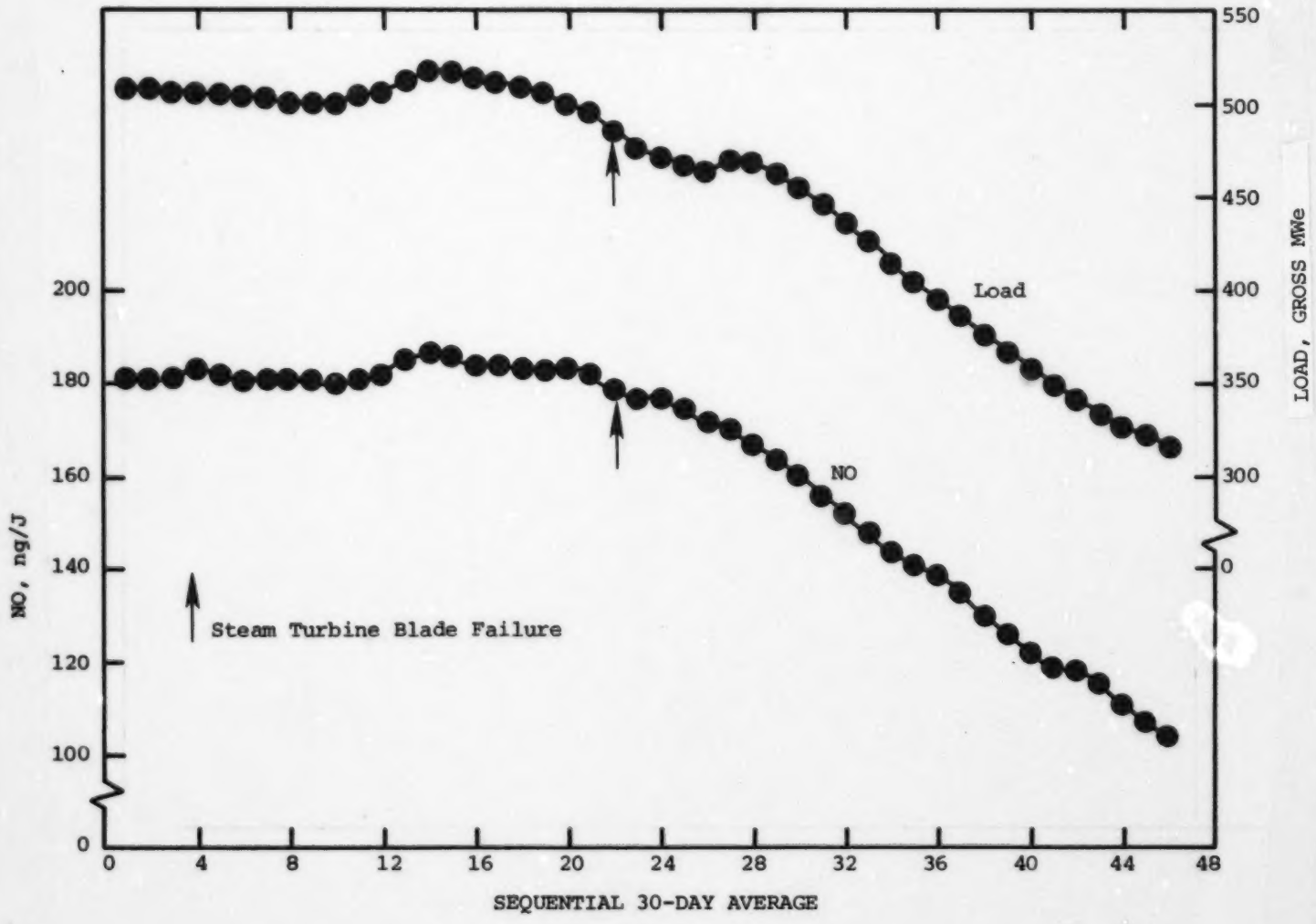


Figure 8-7. NO and Load 30-Day Rolling Averages - Gentleman Unit 1

TABLE 8-1. GENTLEMAN UNIT 1 NO ANALYZER CERTIFICATION

(September 10-17, 1979)

Parameter	EPA Specification	Test Result
Accuracy	< 20% of the mean value of the reference method test data	11.3%*
Calibration error	< 5% of each (50%, 90%) calibration gas mixture value	1.6%, 1.9%
Zero drift (2 Hours)	< 2% of span	0.3%
Zero drift (24 Hours)	< 2% of span	0.5%
Calibration drift (2 Hours)	< 2% of span	0.6%
Calibration drift (24 Hours)	< 2.5% of span	1.0%
Response time	< 15 minutes	2 minutes
Operation period	> 168 hours	168 hours

*On a $lb/10^6$ Btu (ng/J) basis.

TABLE 8-2. GENTLEMAN UNIT 1 O_2 ANALYZER CERTIFICATION
(September 10-17, 1979)

Parameter	EPA Specification	Test Result
Zero Drift (2 Hours)	< 0.4% O_2	0.07%
Zero Drift (24 Hours)	< 0.5% O_2	0.12%
Calibration Drift (2 hours)	< 0.4% O_2	0.09%
Calibration Drift (24 Hours)	< 0.5% O_2	0.09%
Response Time	< 10 minutes	5 seconds
Operational Test Period	> 168 hours	168 hours

TABLE 8-3. GENTLEMAN UNIT 1 NO RELATIVE ACCURACY AND NO_x PERFORMANCE

Date	NO Rel. Acc., %		Performance NO_x	
	ppm	mass	$lb/10^6$ Btu	ng/J
September 10-17, 1979	ND*	11.3	1.10	473
December 11, 1981	23.5	28.1	ND	ND
September 3, 1982	12.9	ND	0.354	152

*ND = Not determined

TABLE 8-4. GENTLEMAN UNIT 1 STATISTICAL CHARACTERISTICS

November 29, 1979 to April 30, 1980

Parameter	Operational Configuration	
	OFAP Closed	OFAP 50% Open
Mean load, gross MWe	345	436
% of rating	50.7	64.1
Median load, gross MWe	350	450
% of rating	51.5	66.2
Mean NO, ng/J	272	151
Median NO, ng/J	270	165
Mean O_2, %, wet	8.26	6.95
Median O_2, %, wet	8.10	6.90

TABLE 8-5. COAL PROXIMATE ANALYSES - GENTLEMAN UNIT 1
August 3, 1979 to May 12, 1980
51 Samples
As-Received Basis

	Mean	Standard Deviation	Coefficient of Variation, %*
% Moisture	27.85	0.43	1.55
% Ash	4.98	0.36	7.25
% Sulfur	0.386	0.0363	9.42
Btu/lb	8,786	66.7	0.76
(kJ/kg)	(20,435)	(155)	(0.76)

*$\%C_v = \frac{\text{Standard Deviation}}{\text{Mean}} \cdot 100$

SECTION 9.0

UNITS D AND E

9.1 INTRODUCTION

Units D and E are pulverized-coal-fired industrial boilers rated at 650,000 lb steam/h (81.9 kg/s) each. The corresponding value of heat input rate is equivalent to an electrical output of approximately 85 MWe for each boiler based on a heat rate of 10,000 Btu/kWh*. These units were manufactured by Babcock & Wilcox and were originally equipped with an air flow vs. coal flow control system which was subsequently replaced by a digital CO (carbon monoxide) system. The O_2 measured at the boiler outlet was not used as a trim-control in the former system.

The primary objective of the analysis reported herein was to quantify the effect of the change in the air control system on long-term NO emissions and heat rate. The characteristics of Units D and E were also to be compared with each other as they are nominally identical boilers.

9.2 BOILER CHARACTERISTICS

Each balanced draft boiler is equipped with 8-single register burners arranged in 2-elevations of 4 burners/elevation on the front face. In addition, four overfire air ports are located above the top row of burners. The overfire air flow was supplied primarily by a separate booster fan whose output was subject to manual control as a function of steam flow.

The overfire air booster fans were subsequently removed due to the lower NO_x levels resulting from the implementation of the CC combustion air control system. Each fan was driven by a 125 bhp (93.2 kW) electric motor. The overfire air flow was then produced by the existing windbox-to-furnace pressure differential. In addition, the dampers which controlled the overfire air flow were placed in an automatic control mode as a function of NO_x.

*Each boiler produces 26 MWe of electric power with the balance of the steam used for process requirements.

9.3 CO CONTROL SYSTEM

The preheated combustion air flow (at approximately 500°F--533 K) is controlled around a CO set-point of 150 ppm in the boiler flue gas. When the CO level is above this set-point the burner secondary air flow is increased to lower the CO level, and vice versa. The burner primary air (for pulverized coal conveyance) is determined by steam load and is not subject to the CO control system. The CO control system was installed during October 1980 but was not fully operational until May 1981. It was originally installed in the SO_x scrubber bypass duct but was subsequently moved to the stack (downstream of the SO_x scrubber).

9.4 PERFORMANCE TESTS

During June 1976 each unit was subjected to the NO_x performance test required by the 1971 New Source Performance Standard (NSPS). The results were a value of 0.678 lb/10^6 Btu (292 ng/J) with the same value for each unit. These tests were conducted prior to the installation of the CO-based combustion air control systems.

Units D and E were performance tested again during April - May 1981 with the CO control systems fully operational. Both units achieved a NO_x level of 0.536 lb/10^6 Btu (230 ng/J) which, when compared to the 1976 results, would indicate that the CO control system produced a 21 percent lower NO_x at high load on a short-term basis. The overfire air booster fans were not in use for these tests.

9.5 CONTINUOUS EMISSION MONITORS

A single Dynascience extractive NO analyzer, sampling stack conditions, was time-shared by both units on a 15-minute cycle. Each unit was also equipped with a dedicated O_2 analyzer located in the stack. The NO analyzer was installed in 1975 and certified during August 22-29, 1977. The O_2 analyzers were certified during November 1978. In addition, each unit was also equipped with a dedicated Measurex in-situ CEM installed in the SO_x scrubber

bypass duct as shown in Figure 9-1. Certification testing of the in-situ Measurex systems was performed during July 25-31, 1983, after they had been moved to the stack, and the Dynascience CEM was then deactivated.

Also noted in Figure 9-1 are the locations of the Measurex CO sampling point which was also moved to the stack during 1983.

Tables 9-1 through 9-5 summarize the certification results for the Dynascience and Measurex systems. Also of note is that the Measurex system is using CO_2 as the dilution correction. The Measurex system for Unit E did not pass the NO_x relative accuracy specification and is scheduled for retest in the near future. The subsequent discussion dealing with a comparison of Units D and E must be qualified based on this result.

9.6 DATA PACKAGES

The facility supplied CEM and steam flow data for both units for the following time periods:

March 1-31, 1981: prior to CO control; Dynascience and Measurex
April 1-30, 1981: with CO control; Dynascience and Measurex
July 15 - August 4, 1983: with CO control; Measurex

However, the certified Dynascience system was inoperative for most of the first and second time periods, when the change to the CO control was accomplished. Thus, long-term NO data from a certified CEM prior to the change was not available.

9.7 DATA ANALYSIS

9.7.1 CEM Comparison

Data from the certified Dynascience CEM was available for March 28-30, 1981 together with data from the uncertified Measurex CEMs (which, at the time, were located in the SO_x scrubber bypass duct). A comparison of the readings from both CEMs is shown in Figure 9-2 and 9-3 for Units D (59 hours) and E (56 hours) respectively. Also shown in these figures are linear regressions between both sets of measurements as well as the ±95 percent confidence limits about both regressions. As noted, the coefficients of determination (r^2) were 0.438 and 0.174, respectively.

A further analysis of the CEM data was performed in a manner similar to that for calculating the relative accuracy of a NO analyzer. In this instance, the hourly averaged NO values from the certified Dynascience CEM were the counterpart of EPA Method 7 which are to be compared to the simultaneous measurements made by a CEM (Measurex) in the certification process.

It is recognized that this procedure cannot be justified by any EPA test method, either proposed or promulgated. However, the objective of the procedure was to determine if any of the data obtained prior to the changeover to the CO based air control systems could be used. On this basis, all results obtained would have to be heavily qualified.

The results of the comparison for the Measurex CEM on Unit D was a "relative accuracy" of 11.80 percent with respect to the Dynascience results. Similarly, the Unit E "relative accuracy" was 25.02 percent. On this basis it was concluded that the Measurex results for Unit E would not be usable since the "relative accuracy" exceeded the EPA specification of 20 percent. It was decided to use the Measurex results to characterize the operation of Unit D prior to the change to the CO-based control system.

9.7.2 Effectiveness of CO Control

An extended version of the data reduction computer program described in Reference 2-1 was used to compare the NO emissions from Unit D for operation both before and after the change to the CO-based air control system. (As was previously mentioned the NO data for pre-CO operation was obtained with uncertified instrumentation.)

Figure 9-4 compares the NO vs. steam flow (load) characteristic developed by sorting the NO into ten equally spaced load cells. (The load cell numbers are shown above the bars in this figure.) There were insufficient data for cells 1 and 2 to make a meaningful comparison. The NO values shown in Figure 9-4 are the mean values within each load cell. In general, the mean NO values for CO control operation are lower than those of O_2 control operation.

Also of note was that the maximum NO emission factor did not occur at the highest load, with this effect being more pronounced for the pre-CO control.

The Unit D data were further analyzed to quantify the differences in NO vs. load resulting from the change in the air control system. This analysis involved the use of the mean NO, NO standard deviation and number of data points in each load cell (cf. Ref. 4-1). The analysis results are shown in Figure 9-5 and at high load agrees reasonably well with the NO_x reduction based on the performance tests (15 vs. 21 percent). As noted, there was no statistical difference in the mean NO values for load cell 6. At low load (48.2-54.8 percent of rating) the NO reduction due to the change in air control systems was 51 percent.

It must be reiterated that the results for Unit D while operating with the pre-CO system were obtained with an uncertified CEM. Therefore, all comparisons with the CO-based system must be qualified. Again it must be noted that the NO analyzer for Unit E did not stisfy the NO_x relative accuracy specificaton.

9.7.3 Comparison of Units D and E

Figure 9-6 compares the NO vs. load characteristics for Units D and E with both units under CO control. As noted, the maximum NO for Unit E also occurs at less than full load. At high load both units are between 13 and 20 percent in excess of their performance test results.

Figure 9-7 quantifies the difference in NO vs. load for the two nominally identical units. There was no statistical difference found for load cells 4 and 10, while differences ranging from 14 to 39 percent were calculated for the other load cells. These results imply that the units were not being operated in an identical manner throughout the load range.

The similarity in the steam flow (load) distributions shown in Figure 9-8 would indicate that both units were being loaded in the same manner. This similarity would eliminate differences in load as a primary cause of the differences in NO, which are compared in Figure 9-9.

9.7.4 Stack O_2 Comparison

As previously mentioned, stack O_2 data was provided for Unit D prior to the change to the CO-based system while CO_2 was used as the dilution

correction for Unit D and E operating with CO-based controls. The approximate stack O_2 was related to CO_2 through the fuel ultimate analyses so that a direct comparison could be made of the stack O_2 for all three conditions. The relationship thus developed was:

$$O_2 \text{ (\%, wet)} = 21.00 - 1.280 \cdot CO_2 \text{ (\%, wet)}$$

This comparison is shown in Figure 9-10 and, unexpectedly, indicated that Unit D prior to CO control was apparently operating at the lowest stack O_2. This occurance is contrary to the trend in NO emissions which showed that Unit D with CO control was a lower emission source, from which it would be inferred that it was also operating at a lower O_2 level. The facility did indicate that the boiler outlet O_2 (as opposed to stack O_2 measurements) could be maintained at 2 percent with the CO control, while previously the units were operating at 4-6 percent O_2. One possible explanation for this occurence would be an increase in air leakage upstream of the O_2 measuring location in the stack after the implementation of the CO system.

9.7.5 Comparison with 1971 NSPS

The data reduction program calculated the number of periods of excess NO with respect to the 1971 New Source Performance Standard on both a 3-hour rolling and 3-hour block average basis. These periods of excess emission (greater than 0.7 $lb/10^6$ Btu--300 ng/J) were then normalized with respect to the total number of 3-hour rolling and block averages which could be formed from the total number of data hours supplied, i.e.:

Number of 3-hour rolling averages = Total number of data hours - 2

Number of 3-hour block averages = Total number of data hours/3

The results of this comparison are shown below:

Unit	Control Mode	% Excess 3-hr Rolling	% Excess 3-hr Block
D	Pre-CO	59.6	65.8
D	CO	34.7	41.9
E	CO	12.2	13.6

As noted, the use of CO control of the combustion air produced a significant decrease in the relative number of excess NO periods with respect to the 1971 NSPS. Again, it must be cautioned that the pre-CO emission data for Unit D was obtained with uncertified equipment and that the NO analyzer for Unit E did not pass the relative accuracy test.

9.7.6 Comparison With 1978 NSPS

The NO probability distributions for Units D and E with CO control (Figure 9-9) indicated that the emissions were less than or equal to the 1978 NSPS limitation (0.6 $lb/10^6$ Btu, 258 ng/J) for 37.2 and 66.2 percent of the time, respectively. If the mean values of NO were used as the compliance criteria (Table 9-6) then only Unit E with CO control would meet this limitation and with less than a five percent margin.

9.7.7 Coal Properties

The coal used by this facility is from their own mine, however, the better quality coal is sold to outside users. As a result, the coal properties for units D and E tend to vary widely, especially the sulfur content.

The facility supplied 11 coal proximate and ultimate analyses for the time period of February - May 1981. These analyses are summarized in Table 9-7 in terms of the mean, standard deviation and coefficient of variation (C_v). Of note is the large variation in sulfur content (C_v = 52.1 percent) which ranged from 0.31 to 1.43 percent by weight.

9.7.8 Efficiency Considerations

During March 1981 each unit was tested specifically to determine the effect of CO control on heat rate (defined as energy consumed/steam flow rate). The minimum load during these tests was 83 percent of rated steam flow. It was found that the heat rate (efficiency) improved by 0.92 and 2.1 percent for Units D and E, respectively. It was assumed that these results included the energy debit due to an increase in unburned carbon, which increased from 0.52 percent with O_2 control to 0.71 percent with CO control.

It was also assumed that the savings in electrical energy due to overfire air booster fan deactivation were not included. This particular energy savings, however, would be equivalent to only a 0.14 percent improvement in efficiency.

9.7.9 Operational Impacts

The operator of Units D and E indicated that the CO-based control system has not caused any significant increase in slagging. It has been observed that the slag that does form appears to be located lower in the furnace than previously observed. No fouling or corrosion problems have been noted.

9.8 CONCLUSIONS

Analysis of CEM data and performance test results for Units D and E indicates that:

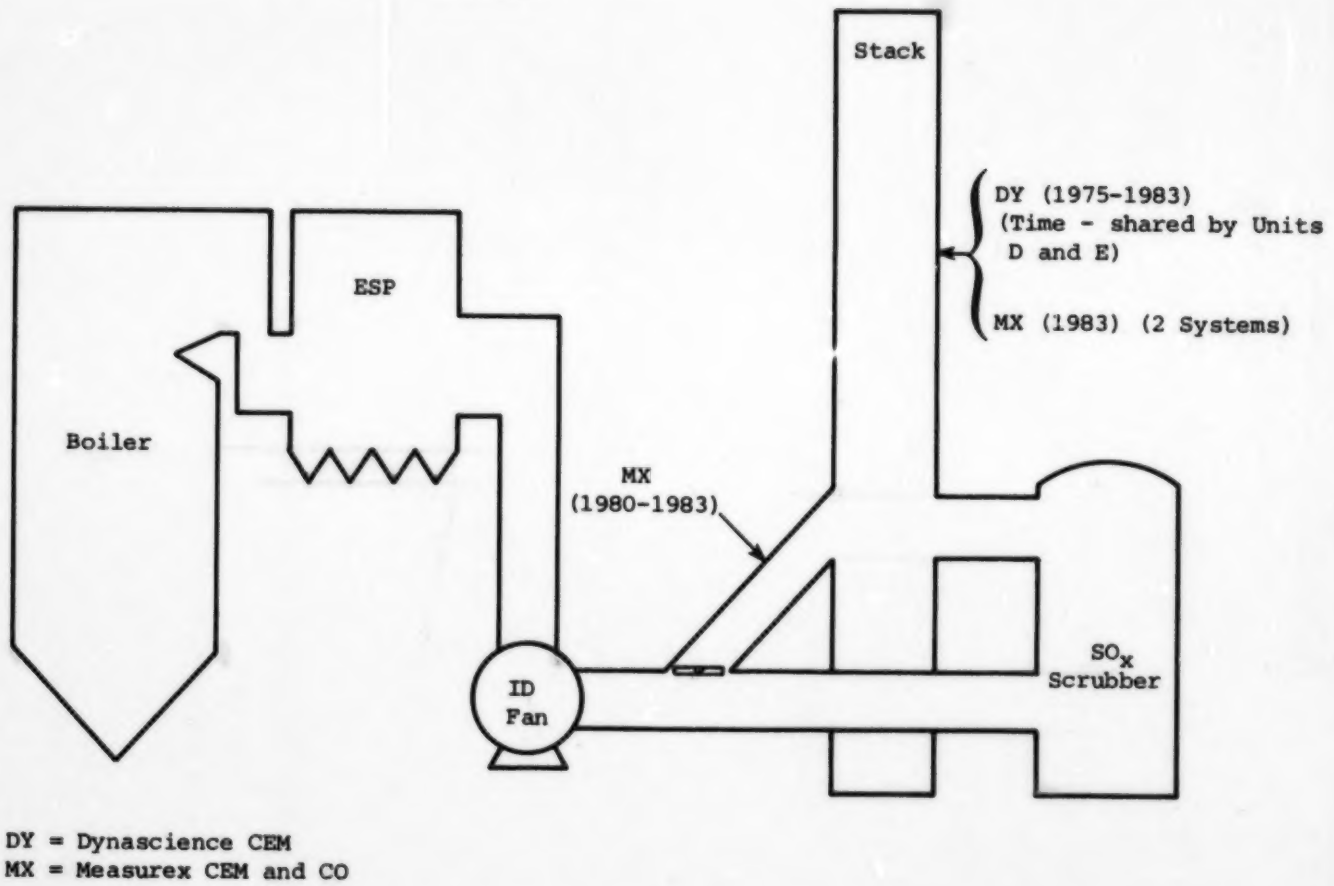
1. The CO-based air supply system achieved a NO_x reduction of approximately 15 percent. This result is uncertain since the pre-CO control data was obtained by uncertified equipment.

2. The performance tests conducted on these units indicates a short-term NO_x reduction of 21 percent.

3. There were statistically significant differences in NO vs. load for these nominally identical units while both were operating with the CO-based controls.

4. The CO-based controls are credited with efficiency improvements of 0.92 and 2.1 percent for Units D and E, respectively.

5. There have been no adverse operational impacts attributed to the CO-based controls.



DY = Dynascience CEM
MX = Measurex CEM and CO

Figure 9-1. CEM and CO Sampling Locations - Units D and E

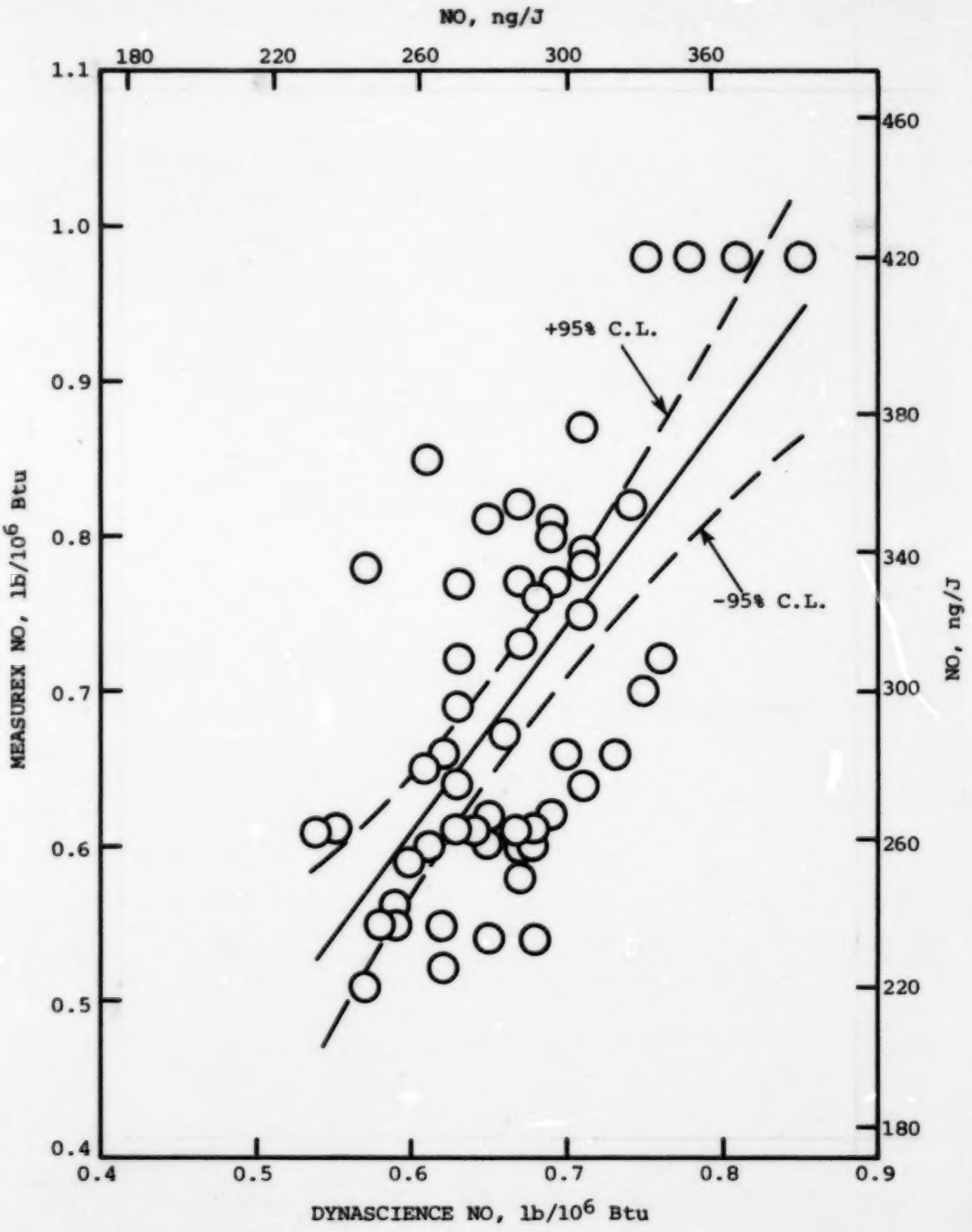


Figure 9-2. Comparison of NO Analyzers - Unit D
March 28-30, 1981
Coefficient of Determination $r^2 = 0.438$

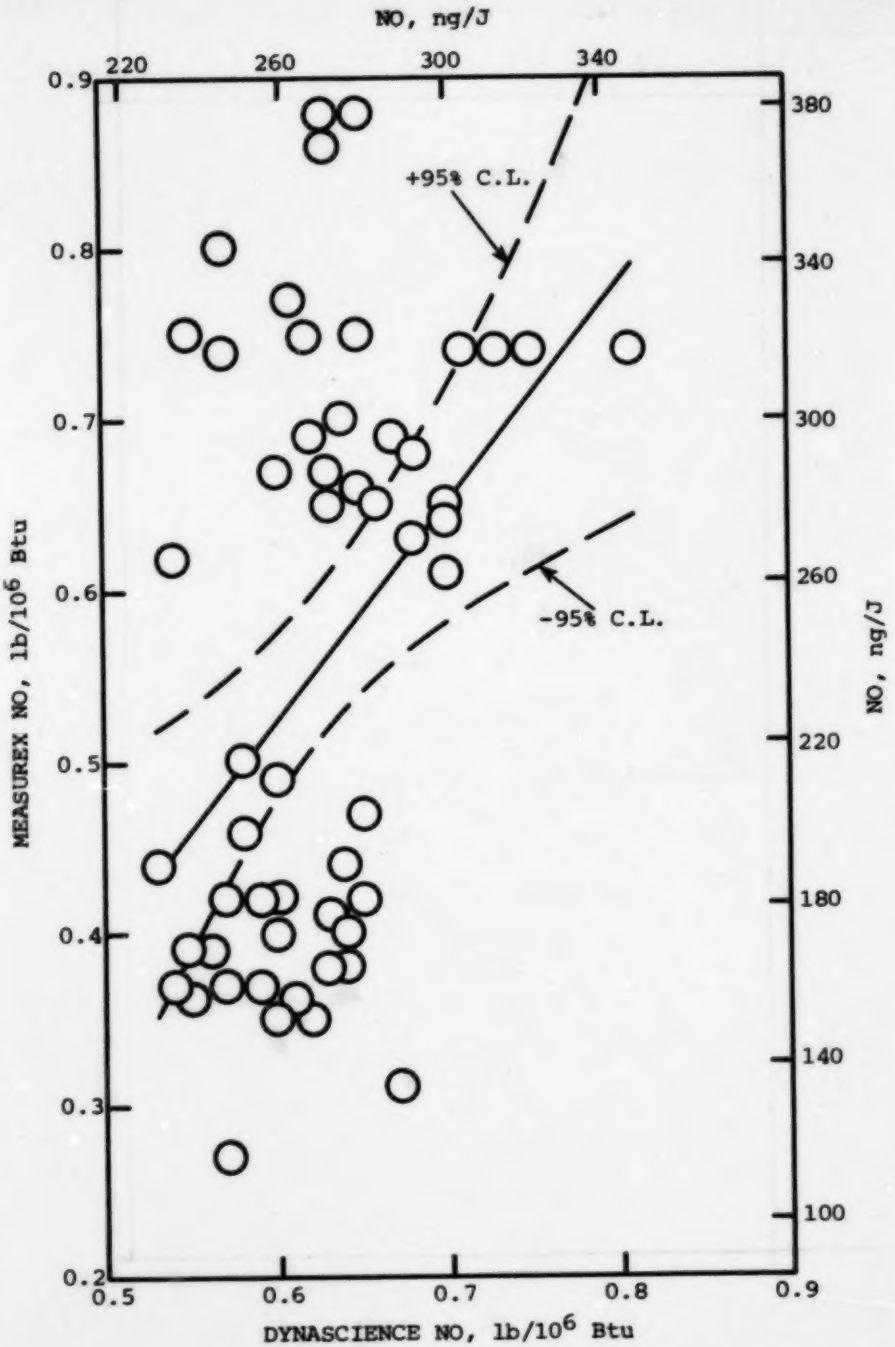


Figure 9-3. Comparison of NO Analyzers - Unit E
March 28-30, 1981
Coefficient of Determination $r^2 = 0.174$

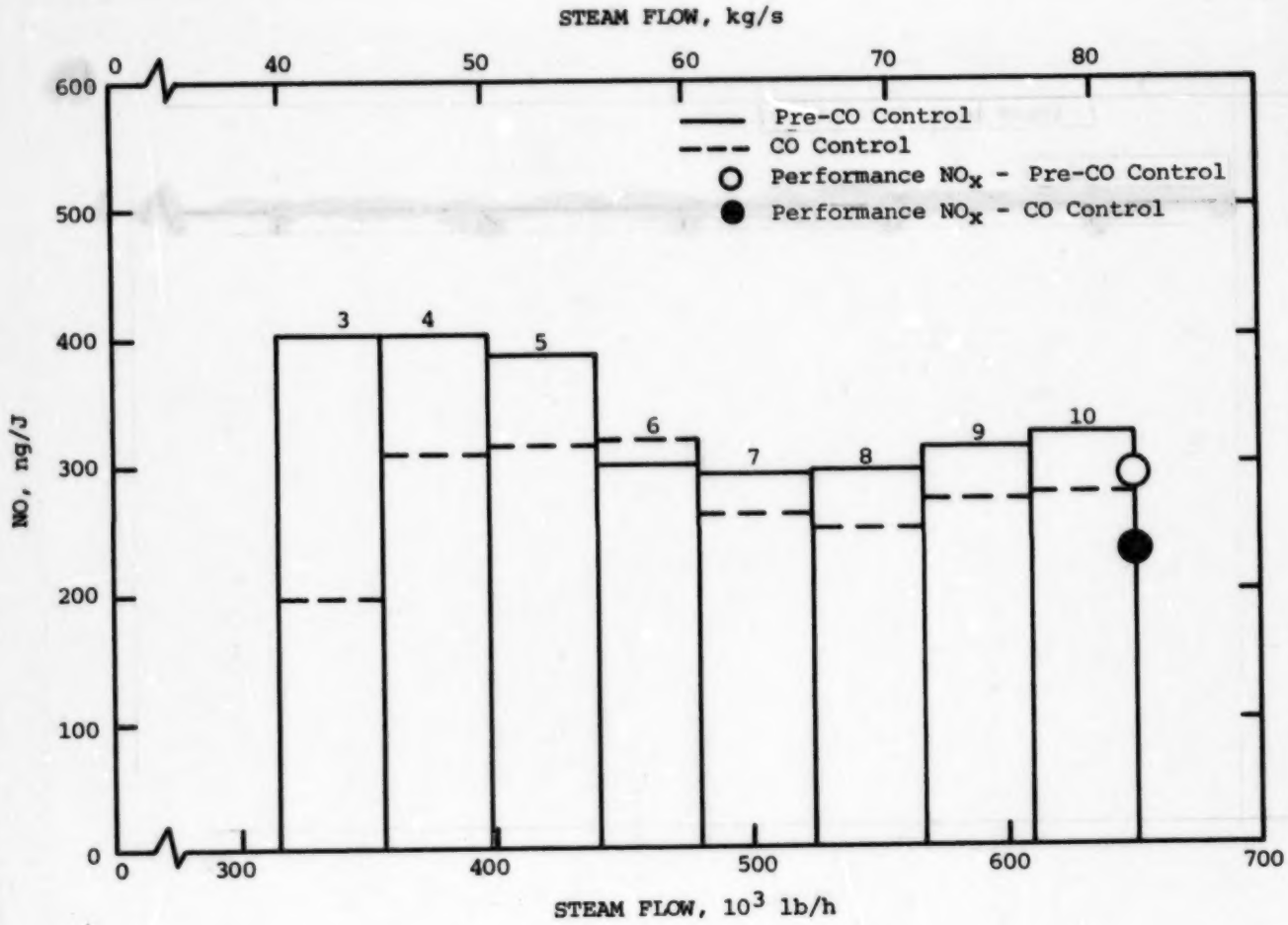


Figure 9-4. Unit D NO versus Load Comparison

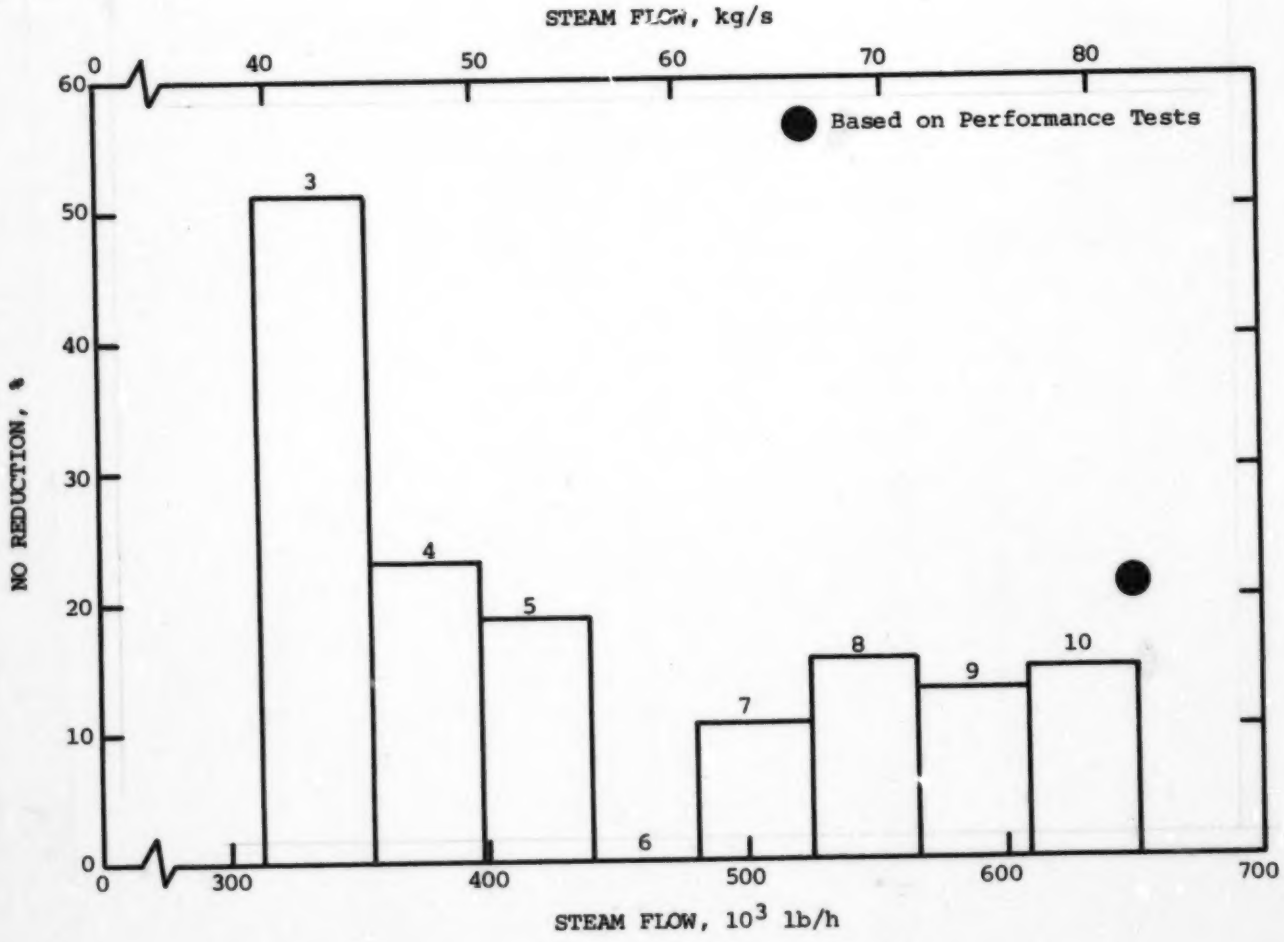


Figure 9-5. Unit D NO Reduction

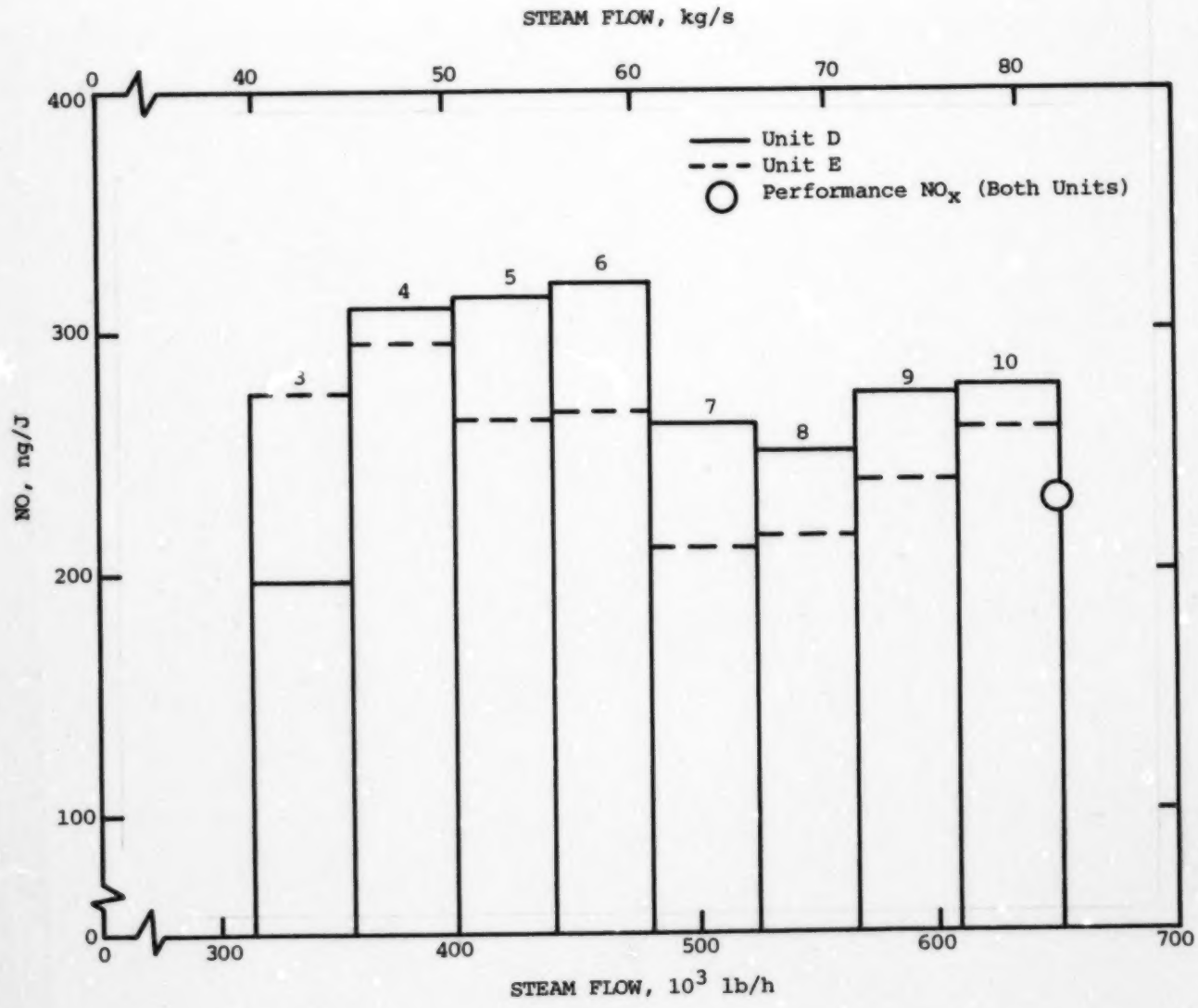


Figure 9-6. NO versus Load Characteristics for Units D and E with CO Control

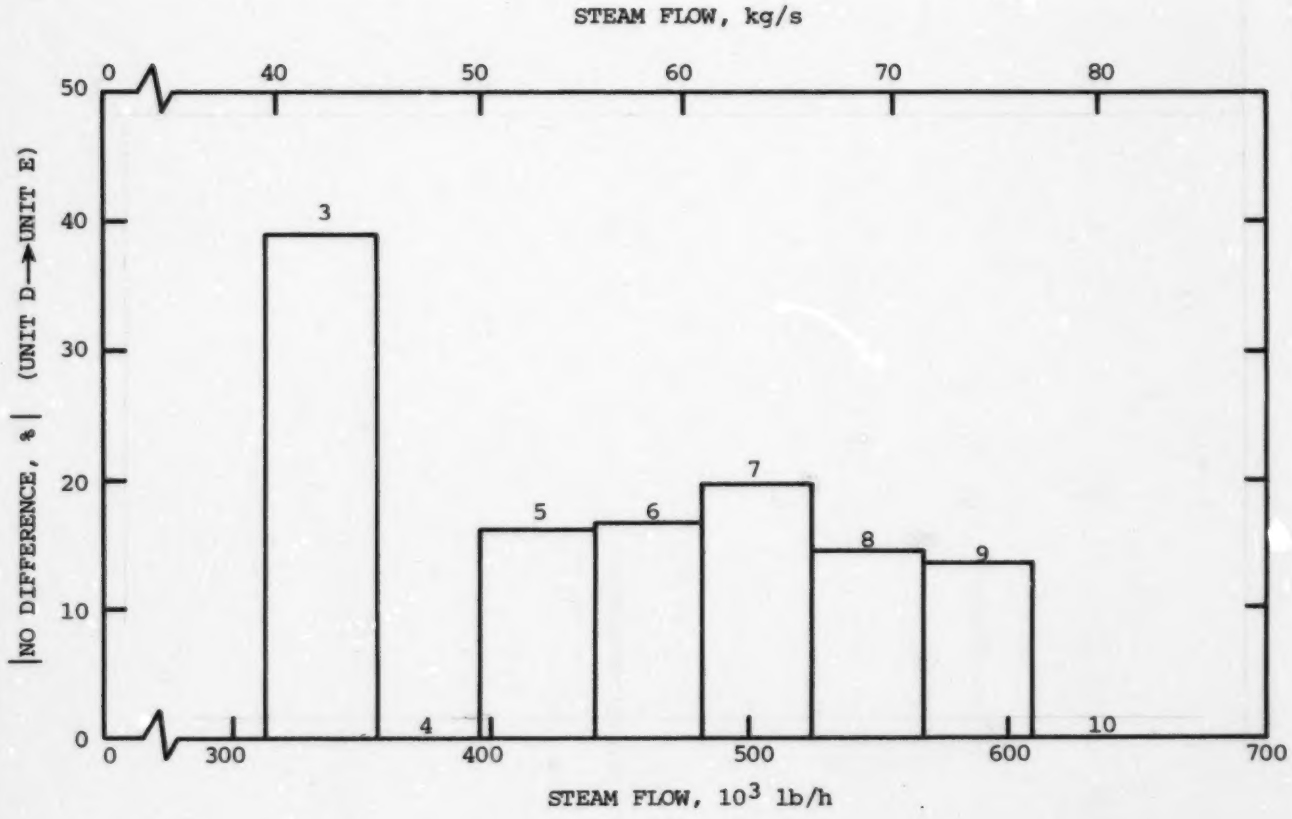


Figure 9-7. NO Comparison between Units D and E with CO Control

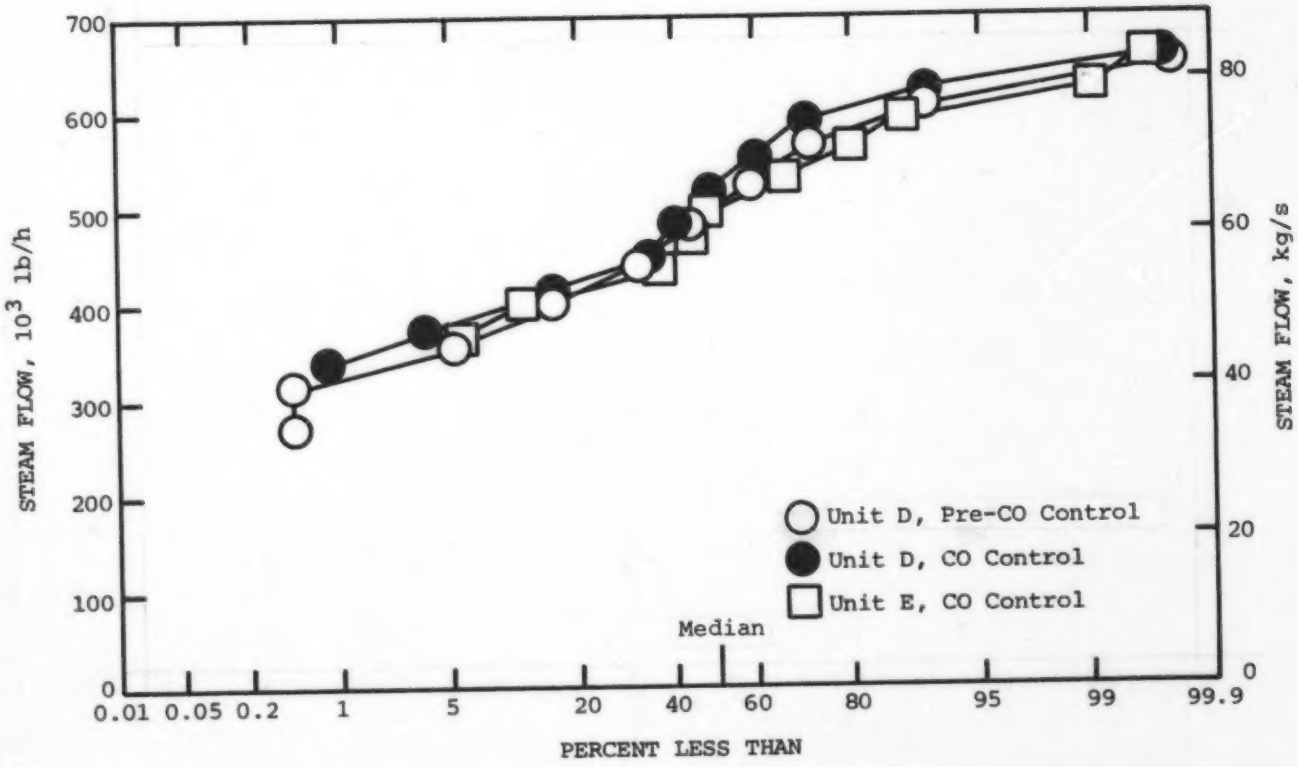


Figure 9-8. Steam Flow Probabilities for Units D and E

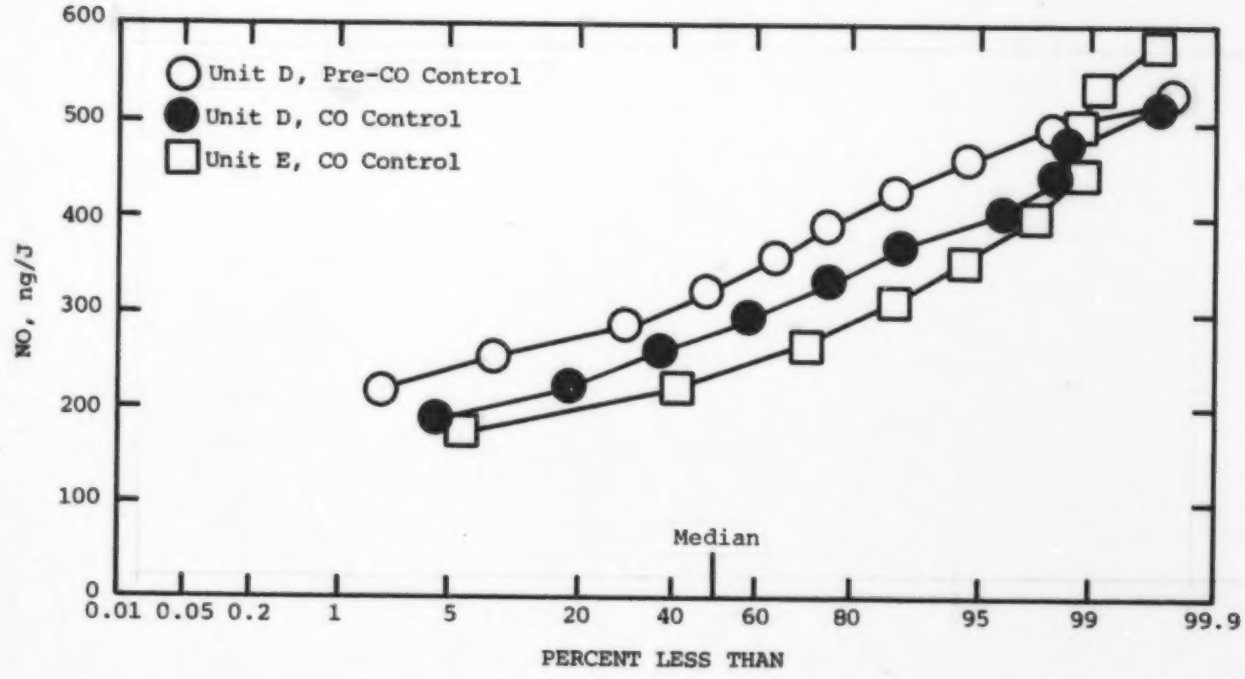


Figure 9-9. NO Probabilities for Units D and E

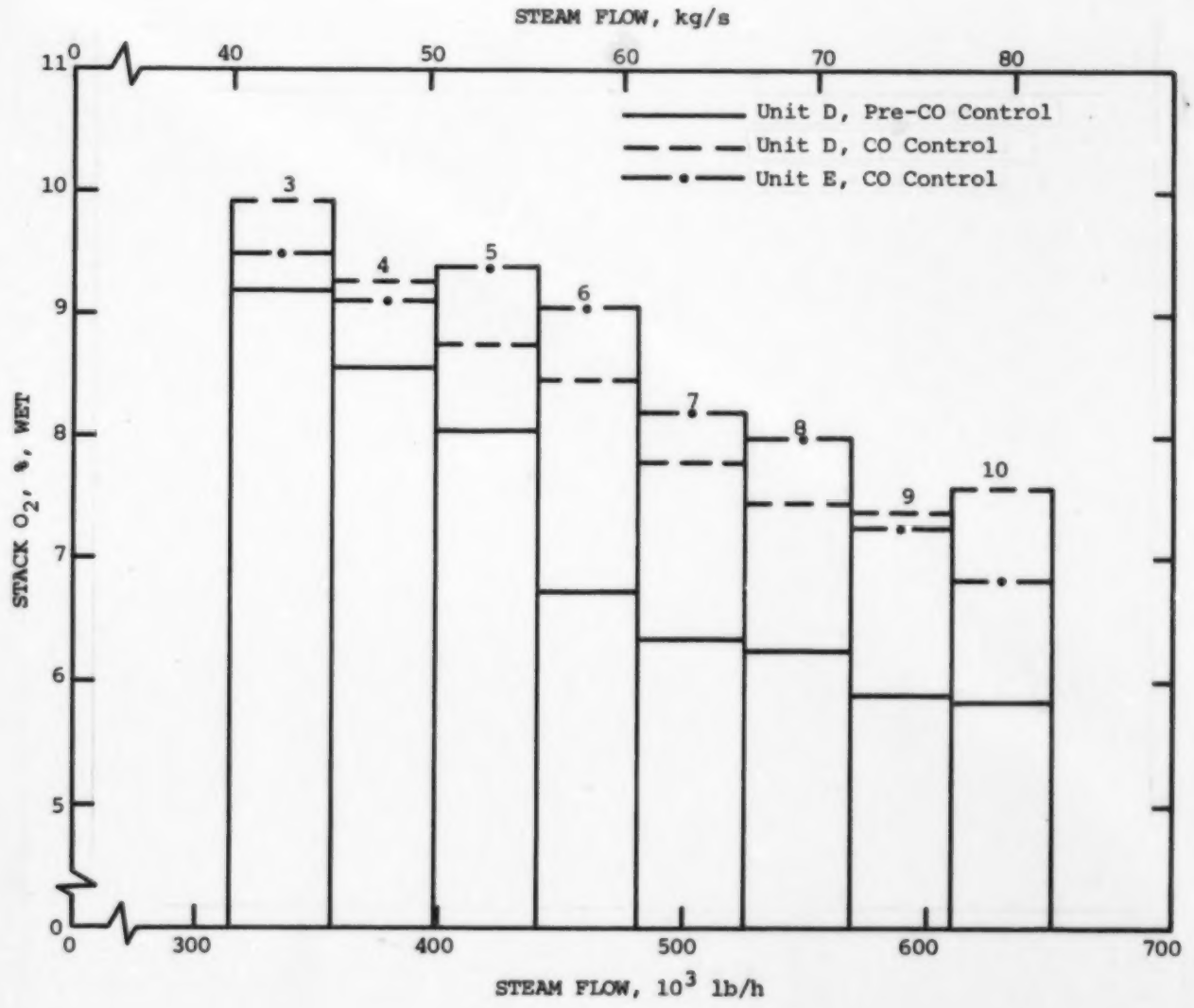


Figure 9-10. Stack O_2 Comparison

TABLE 9-1. DYNASCIENCE NO ANALYZER CERTIFICATION RESULTS

August 22, 1977 Through August 29, 1977

Units D and E*

Paramenter	Specification	Test Results	
Accuracy	≤ 20%	13.8%	
		Mid	High
Calibration Error	≤ 5%	2.49%	0.31%
Zero Drift 2-Hour	≤ 2% of span	0.616% of span	
Zero Drift 24-Hour	≤ 2% of span	1.083% of span	
Calibration Drift 2-Hour	≤ 2% of span	2.069% of span	
Calibration Drift 24-Hour	≤ 2.5% of span	3.657% of span	
Response Time	≤ 15 minutes	161 sec	
Conditioning Period	≥ 168 hours	>168 hours	
Operational Test Period	≥ 168 hours	168 hours	

*Time-shared NO analyzer

TABLE 9-2. UNIT D OXYGEN ANALYZER CERTIFICATION

November 1978

Paramenter	Federal Regulation Requirement	Certification Test Results
Zero Drift 2-hour	$\leq$ 0.40% O_2	0.021%
Zero Drift 24-hour	$\leq$ 0.50% O_2	0.078%
Zero Drift 2-Hour	$\leq$ 0.40% O_2	0.287%
Calibration Drift 24-Hour	$\leq$ 0.50% O_2	0.302%
Operational Period	168 hr (min)	168 hr
Response Time	10 min (max)	7.7 sec

TABLE 9-3. UNIT E OXYGEN ANALYZER CERTIFICATION

November 1978

Paramenter	Federal Regulation Requirement	Certification Test Results
Zero Drift 2-hour	$\leq$ 0.40% O_2	0.000%
Zero Drift 24-hour	$\leq$ 0.50% O_2	0.049%
Zero Drift 2-Hour	$\leq$ 0.40% O_2	0.175%
Calibration Drift 24-Hour	$\leq$ 0.50% O_2	0.241%
Operational Period	168 hr (min)	168 hr
Response Time	10 min (max)	6.9 sec

TABLE 9-4. UNIT D MEASUREX CEM CERTIFICATION RESULTS
July 25-31, 1983

	Specification	Certification Test Results
Performance Specification 2 -NO_x		
- Relative Accuracy	<20%	13.30%
- Calibration Error, mid/high	<5%	3.17%/3.10%
- Zero Drift, 24-hour	<2%	0.14%
- Calibration Drift, 24-hour	<2.5%	0.29%
- Zero Drift, 2-hour	<2%	0.47%
- Calibration Drift, 2-hour	<2%	0.92%
- Response Time	15 min (max)	4.2 sec
- Operational Test Period	168 hr (min)	212
Performance Specification 3 - CO_2		
- Zero Drift, 24-hour	<0.5%	0.03%
- Calibration Drift, 24-hour	<0.5%	0.12%
- Zero Drift, 2-hour	<0.4%	0.10%
- Calibration Drift, 2-hour	<0.4%	0.22%
- Response Time	10 min (max)	3.2 sec
- Operational Test Period	168 hr (min)	212

TABLE 9-5. UNIT E MEASUREX CEM CERTIFICATION RESULTS

July 25-31, 1983

	Specification	Certification Test Results
Performance Specification 2 - NO_x		
- Relative Accuracy	<20%	23.67%*
- Calibration Error, mid/high	<5%	2.55%/1.90%
- Zero Drift, 24-hour	<2%	0.46%
- Calibration Drift, 24-hour	<2.5%	0.37%
- Zero Drift, 2-hour	<2%	0.10%
- Calibration Drift, 2-hour	<2%	0.10%
- Response Time	15 min (max)	1.6 sec
- Operational Test Period	168 hr (min)	207
Performance Specification 3 - CO_2		
- Zero Drift, 24-hour	<0.5%	0.08%
- Calibration Drift, 24-hour	<0.5%	0.23%
- Zero Drift, 2-hour	<0.4%	0.07%
- Calibration Drift, 2-hour	<0.4%	0.08%
- Response Time	10 min (max)	3.6 sec
- Operational Test Period	168 hr (min)	207

*To be retested

TABLE 9-6. STATISTICAL RESULTS FOR UNITS D AND E

	Unit D Pre-CO Control	Unit D CO Control	Unit E CO Control
Mean NO, ng/J	335	287	246
Median NO, ng/J	322	280	232
Mean Steam Flow - 10^3 lb/h	492	507	486
- kg/s	62.0	63.9	61.2
- % of Rating	75.7	78.0	74.8
Median Steam Flow - 10^3 lb/h	500	520	500
- kg/s	63.0	65.5	63.0
- % of Rating	76.9	80.0	76.9
Mean CO_2, %	*	10.1	9.8
Median CO_2, %	*	10.2	10.0
Number of Data Points	448	351	330

*O_2 used for dilution correction

TABLE 9-7. COAL ANALYSES FOR UNITS D AND E
February - May 1981
11 Samples
As - Received Basis

Parameter	Mean	Deviation	C_v, %*
% Moisture	18.9	3.90	20.7
% Volatile	36.9	2.10	5.7
% Fixed Carbon	39.5	2.76	7.0
% Ash	4.75	0.90	18.9
Heating Value - Btu/lb	10,175	445	4.4
- kJ/kg	23,667	1,035	4.4
% Hydrogen	6.77	0.46	6.8
% Carbon	58.6	2.57	4.4
% Nitrogen	0.91	0.07	7.4
% Oxygen	28.19	3.25	11.5
% Sulfur	0.81	0.42	52.1
% Ash	4.75	0.90	18.9

*C_v, % = $\frac{\text{Standard Deviation}}{\text{Mean}} \cdot 100$

SECTION 10.0

CONCLUSIONS AND RECOMMENDATIONS

As it will be recalled, the primary objective of this Work Assignment was the quantification of the long-term effectives of combustion modifications in reducing NO_x emissions from several pulverized-coal-fired steam generators. This objective was completely satisfied.

High load NO_x reductions ranging from 5.1 percent to 60 percent have been determined from the analyses conducted on eight pulverized-coal-fired steam generators. These reductions have resulted from the implementation of combustion modifications ranging from lower excess air* to optimization of the overfire air system.

All of these modifications (except lower excess air) were implemented for the express purpose of reducing NO_x emissions from existing steam generators. It was also determined that these modifications did not produce any significant adverse impacts on unit operation.

Efficiency data was available for three of the steam generators both before and after the modification (lower excess air and CO-based control system). These modifications produced efficiency gains on the order of 1 - 3 percent.

The eight steam generators analyzed were all subject to the NO_x provisions of the 1971 New Source Performance Standards (NSPS). It is recommended that the analysis be extended to utility units which are subject to the 1978 NSPS. The NO_x levels and averaging period have been changed with respect to the 1971 NSPS. Possibly, the boiler design criteria have also changed in order to comply with the new provisions.

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*Iowa Power & Light, Council Bluffs Unit 3 actually increased excess air in an attempt to reduce slagging tendencies. The NO_x reduction quoted is with respect to the previous lower excess air operation for which long-term data was also available.

This assessment would be conducted in cooperation with the EPA Regional Offices and boiler manufacturers to both:

1. Identify the units.
2. Ascertain revised design criteria.

The unit operators will be asked to provide emission data and load in order to quantify the long-term NO_x levels. Of particular interest would be those units which are operated at a significant percentage of their rated output for extended periods of time. These base loaded units do not have the operational flexibility to "average-in" potentially lower NO_x values at reduced load.

SECTION 11.0

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